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PUBLIC UTILITIES COMMISSION
21 S. Fruit Street, Suite 10
Concord, N.H. 03301-2429

Tel. (603) 271-2431

FAX (603) 271-3878

TDD Access: Relay NH
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October 19, 2009

Debra A. Howland
Executive Secretary
New Hampshire Public Utilities Commission
21 South Fruit Street Suite 10
Concord, New Hampshire 03301

Re: Docket No. DE 09-091
Public Service Company of New Hampshire
2008 Reconciliation of Energy Service and Stranded Cost Recovery Charges
Testimony of Michael J. Cannata, Jr., The Liberty Group

Dear Ms. Howland:

Pursuant to the modified procedural schedule, I enclose an original and 7 copies of the testimony and related schedules of Michael J. Cannata, Jr. in the above-captioned docket. Staff retained Mr. Cannata of The Liberty Group as the engineering expert in this proceeding.

Mr. Cannata's testimony references three responses to data requests for which Public Service Company of New Hampshire has filed motions for confidential treatment. The data requests and responses will be filed as a confidential addendum to Mr. Cannata's testimony.

Copies of this letter and the testimony will be filed electronically with the parties on the service list. Please let me know if you have any questions.

Sincerely,

Suzanne Amidon, Esq.
Staff Attorney

Service List

STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 09-091

IN THE MATTER OF:
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE, INC.
2008 ENERGY SERVICE AND STRANDED COST RECOVERY CHARGE RECONCILIATION

DIRECT TESTIMONY

OF

MICHAEL D. CANNATA, JR., P. E.
SENIOR CONSULTANT
FOR
THE LIBERTY CONSULTING GROUP

OCTOBER 19, 2009

Q. Mr. Cannata, please state your full name.

A. My name is Michael D. Cannata, Jr.

Q. Please state your employer and your business address?

A. I am employed by Innovative Alternatives, Incorporated (IAI) and am engaged by The Liberty Consulting Group (Liberty) to address the issues raised in this proceeding. My business address is 65A Ridge Road, Deerfield, New Hampshire 03037.

Q. In what capacity are you employed?

A. I am a principal with IAI and in that role I am generally responsible for the review of energy utility engineering and operations management, practices, and procedures.

Q. Please describe your educational background, work experience, and major accomplishments of your professional career?

A. My educational background, work experience, and major career accomplishments are contained in Exhibit MDC-1.

Q. To what professional organizations or industry groups do you belong or have you belonged?

A. I am a member of the Institute of Electrical and Electronic Engineers and its Power Engineering Society, and am a Registered Professional Engineer in the State of New Hampshire (#5618). I served as a member of virtually all of the former New England

Power Pool (NEPOOL) Task Forces and Committees except for their Executive Committee where my role was supportive to an Executive Committee member. I also served as a member of the New England/Hydro Quebec DC Interconnection Task Force and the Hydro Quebec Phase Two Advisory Committee. These two groups designed the Hydro Quebec Phase One and Phase Two 450kV DC interconnections with New England. The various committees and groups that I have served on existed to address the functions now being performed by the Independent System Operator – New England (ISO-NE).

On national issues, I represented Public Service Company of New Hampshire (PSNH) at the Northeast Power Coordinating Council as its Joint Coordinating Committee member, at the Edison Electric Institute as its System Planning Committee member, and at the Electric Power Research Institute as a member of the Power Systems Planning and Operations Task Force.

While in the employ of the State of New Hampshire, I sat as a full member of the New Hampshire Site Evaluation Committee responsible for siting major energy facilities (generating stations, gas transmission lines, electric transmission lines, and gas storage facilities). At the request of the New Hampshire Public Utilities Commission's (NHPUC or Commission) Chairman, I sat on the State Emergency Response Commission. I was also a member of the former Staff Subcommittee on Engineering of the National Association of Regulatory Utility Commissioners.

Q. Have you testified before regulatory bodies before?

A. I have testified before the NHPUC in rate-case, condemnation, least-cost-planning, fuel-adjustment, electric industry restructuring, unit outage reviews, and other proceedings, the Kentucky Public Service Commission and the Maine Public Utilities Commission in transmission siting proceedings, and have submitted testimony at proceedings at the Federal Energy Regulatory Commission (FERC). I have also testified at the request of the Commission before Committees of the New Hampshire Legislature on a variety of matters concerning regulated utilities.

Q. Please describe the areas that your testimony addresses today.

A. My testimony addresses four areas. Liberty was requested to review (1) the market-based capacity/energy planning performed by PSNH during 2008 that augmented its own generation to supply Energy Service to PSNH customers, (2) the outages that occurred at all PSNH generating units during 2008, (3) additional recommendations that have surfaced as a result of my investigation of unit outages and (4) the review of PSNH's efforts to address the eight additional recommendations contained in Section IV.c of the Stipulation and Settlement Agreement in Docket 08-066. I also express my views regarding the availability and capacity factors of PSNH generating units for 2008, the value of Newington Station to customers, and the adequacy of future capital and O&M expenditures for sound plant operations.

This testimony addresses the review areas either through the questions and answers presented below or through a series of individual reports, which are attached to my testimony and are organized as follows.

Capacity/Energy Planning:

Exhibit MDC-2, 2008 Capacity/Energy Planning.

Generating Unit Outages:

Exhibit MDC-3, Merrimack Outages For 2008

Exhibit MDC-3A – Liberty Assessment of Economics of the Merrimack Unit 2 HP/IP Turbine Replacement in 2008

Exhibit MDC-4, Newington Outages For 2008

Exhibit MDC-5, Schiller Unit Outages For 2008

Exhibit MDC-6, Hydroelectric Unit Outages For 2008

Exhibit MDC-7, Combustion Turbine Outages For 2008

Exhibit MDC-8, W. F. Wyman Outages for 2008

Q. Please summarize your capacity and energy planning testimony.

A. With regard to capacity and energy planning, Liberty concluded that the PSNH filing is an accurate representation of the capacity and energy purchasing process that took place in 2008, and that PSNH made sound management decisions with regard to its capacity and energy purchases in a market environment. Liberty reviewed the capacity and energy testimony filed by PSNH, conducted an on-site interview with knowledgeable personnel responsible for the capacity and energy planning function at PSNH, requested follow-up information, and reviewed detailed, backup information of the summary results supplied by PSNH. Liberty also concluded that the capacity factor projections for PSNH units used for 2008 market purchases were reasonable and included ongoing discussions with generating plant personnel. Liberty also confirmed that PSNH did model changes in unit maintenance scheduling reflecting short, planned reliability outages in 2008 as agreed to in a previous proceeding. Liberty also concluded that customer migration introduced volatility into planning future PSNH customer energy service needs because of the difficulty in planning purchases for unknown customer decisions.

Q. Do you have recommendations regarding capacity and energy planning issues?

A. No. PSNH used the same supplemental energy purchase philosophy in 2008 as it did in 2007. PSNH chose to keep this approach to market supplemental purchases in order to minimize risks due to customer migration and market price.

Q. Please state the results of your review of the PSNH unit outages that occurred during 2008.

A. With regard to planned and forced unit outages, Liberty found that the base load units on the PSNH system ran well in 2008. In fact, PSNH units generally performed as well or better than forecasted. Such output is of note because, over time, unit operation has become more complicated, or unit output has been reduced by increased safety requirements dealing with confined spaces, with the addition of spray modules in the outlet canal at Merrimack, with the reduction of the operating level of Unit 2 at Merrimack to reduce the likelihood of full load trips to maintain the unit's reliability, with the installation of supplemental electrostatic precipitators and SCRs on both units at Merrimack, and the use of low sulfur coal to comply with state and federal environmental regulations.

Liberty reviewed outage information, conducted on-site interviews, and submitted follow-up requests for information as necessary. In each instance except those noted below, Liberty found the outages to be reasonable and not unexpected for the particular unit, its vintage, or the outage was necessary for proper operation of the unit. Liberty also concluded that PSNH conducted proper planning and management oversight regarding these planned and forced unit outages. Liberty also has recommendations from its review of unit outages that it believes will improve the operation of PSNH's generating units.

Q. Which outages did you find unreasonable?

A. The first outage that Liberty believes to be unreasonable is associated with Newington Outage 1-C on 3/14/08 as identified in Exhibit MDC–4. This outage occurred when the upgraded turbine control system required adjustments to be made exactly at 3600 rpm. Tuning of the speed control was performed and the unit ramped to full load but was cycled off line in the evening due to economics. This outage was taken the next day to make those turbine control system adjustments, the time was expected, and had been included in the outage schedule to do so.

The unit was operating at 3600 rpm and de-energized when the closed cooling water plunger seat cracked in the solenoid valve that prevented cooling water from flowing to the two exciter coolers. As a result, the air temperature of the exciter began to rise. An alarm came into the unit operator when the exciter temperature reached 110 degrees F. This alarm, a high cool air alarm, is a warning alarm, and when reached, procedures require that the operator investigate its cause. A duplicate alarm came in approximately 2 ½ minutes later. No investigation to the cause of the alarms was made. Subsequent to the first alarms and 24 minutes later, a second alarm came into the control room. This alarm occurs when the exciter temperature reaches 170 degrees F, is called a high hot air temperature alarm, and when reached, procedures state that the operator is required to investigate/validate and/or shut the unit down. A duplicate alarm came in approximately nine minutes later. The operator acknowledged all four alarms as a group to clear the alarm screen. The operator failed to investigate the alarms and convinced himself that these alarms were not consistent with a de-energized unit. The operator therefore did not initiate a unit shut down. Due to these operator actions/inactions, the exciter was damaged.

Liberty recommends a disallowance for the replacement power costs associated with this outage as the PSNH operator should have followed established procedures rather than rationalize alternative actions. Temperature, flow, and pressure alarms are some of the most important alarms to occur in a generating station. In addition and simplistically, temperature alarms originate from temperature probes that report temperatures independent of the operational status of the unit. Liberty does not recommend disallowance of net capital costs or net O&M costs associated with this outage due to the complexities of valuing plant in service beyond its book service life and other material facts such as insurance etc. Upon investigation of the incident and to address contributing factors, PSNH has re-emphasized the requirement to follow established procedures and monitor alarms, is continuing training start up exercises every two weeks at Newington (a program initiated just prior to this incident), initiated a comprehensive review of alarm management practices, and disciplined the operator on duty at the time. The specific incident at Newington and these lessons learned programs such as alarm management are also being emphasized at Merrimack and Schiller stations.

Although Liberty recommends disallowance for replacement power costs for this outage, Liberty commends the operator involved and PSNH for developing a culture at the generating stations in which the operators and other personnel feel comfortable in stepping forward and taking responsibility for their actions. Such a culture can do nothing but improve plant performance.

The second outage is Outage Newington 1-D that occurred on 4/10/08, is related to the damaged exciter noted above, and is identified in Exhibit MDC-4. When returning to service from the installation of the Siemens' spare exciter rotor, balancing was required when the unit was phased. This outage was taken to accomplish that balancing. The rotor was balanced in the shop, but shop balancing does not exactly match field conditions. The rotor was balanced and the unit returned to service.

Liberty recommends a disallowance for the replacement power costs of this outage as the outage would not have been required but for the improper operator actions described in Outage C above.

The next outage is Outage Garvins 4-D which occurred on 12/28/08 as identified in Exhibit MDC-6. A low oil alarm for the lower guide bearing was received by the dispatcher. When a station operator arrived he found that the oil pump was not returning oil from the bearing sump to the bearing reservoir fast enough. The unit was immediately taken off line. Investigation found that the oil return line was being restricted by a kink in the line. The line was replaced and the unit returned to service.

A kink in the oil return line has to occur from human handling during normal cleaning operations or other work related to the return lube oil system. When dismantling and reassembling the oil return line, it must be moved to allow line up of the connections. Liberty believes that an operator did not exercise due care during one of these operations. Further, the operator should have known the oil line was kinked, should have known that oil flow could be restricted to the reservoir, and should have either replaced the line immediately or as soon as possible. Liberty recommends disallowance of replacement power costs for this outage. Liberty also recommends that PSNH review its procedures when a low oil alarm is received by the dispatcher because the dispatcher is unable to determine if low oil is no oil. Allowing the unit to run until an operator arrives may cause unnecessary damage.

The next outage is Outage Jackman 1-E which occurred on 5/5/08 as identified in Exhibit MDC-6. During the upgrade of the transmission side of the substation, a transmission contractor's excavator boom contacted the generator output cables that connect to the generator step up transformer. The contact resulted in the failure of the generator step up transformer. No injuries were reported. Inspection revealed that no other equipment was damaged during the incident. The outage was required to allow time to bring in a mobile transformer replacement. The mobile transformer only allowed operation of the unit up to 2.2 MWs which is lower than the unit's capability.

The contractor had swapped out the smaller machine being used in the grading of the substation. PSNH specifically instructed the contractor not to use the larger machine inside the substation, but when the PSNH inspector left, the larger machine was brought into the substation to perform the remaining work tasks. The incident occurred even though the contractor had a ground spotter who was determined to be "inattentive" at the time of the incident.

The contractor has accepted total responsibility for the incident and PSNH is pursuing financial compensation including replacement power costs.

For the contractor to directly ignore PSNH instructions indicates a significant weakness in the understanding between PSNH and contractors working in PSNH substations and the authority of the contractor to change PSNH instructions. Liberty also notes that PSNH supervision was heavily concentrated at the Mammoth Road TB-73 transformer upgrade project at the time of this incident. Liberty recommends disallowance of replacement power costs for this outage and that PSNH require that contractors comply with PSNH inspector specifically stated instructions. $59,980

The next outage is Outage Jackman 1-H which occurred on 11/6/08 as identified in Exhibit MDC-6. The unit tripped off line while a transmission contractor was performing relay and control work in the substation. Investigation found that circulating current of approximately 1 amp was flowing in the CT residual circuit (CT circuit shorted and bus de-energized condition) and was sufficient enough to initiate the trip. A potential of 0.19 volts existed between the point of grounding of the relay ground and the relay cabinet. The unit was returned to service. Further work included the installation of new 4/0 ground conductors between the old control house and the new 115 kV control house to reduce the potential difference between them.

When doing incremental projects in old substations, grounding configuration, adequacy, and location may not be fully known. A ground potential check should be done to ensure proper grounding between the existing and new work. A ground potential check was not part of this project and Liberty recommends disallowance of replacement power costs for this outage.

The next outage is Outage Jackman 1-I which occurred on 12/2/08 as identified in Exhibit MDC-6. The unit tripped when transmission contractors working in the substation caused the auxiliary breaker on the mobile 34.5 kV substation to operate and in turn caused the trip of the unit. During the removal of the front access panel in the distribution control room, a breaker for the mobile substation popped out of place. This panel is similar to the breaker panel a residential homeowner has in the basement. A white caution tag had been installed on the panel indicating that operation of this breaker would trip the unit. When the face panel was removed, the breaker was activated and the unit tripped. The breaker was reset and the unit returned to service.

In recent years, there has been numerous transmission contractor related outages at hydro stations and many of them appear due to speed of work and therefore lack of due care. In this case, the breaker could not have tripped unless it was bumped during a hasty removal of the panel cover or the white tag became entangled in the panel cover upon removal. In either case, due care was not exercised. There appears to be a weakness in the PSNH/contractor relationship on the expectation of due care to be exercised when in PSNH substations. Liberty recommends disallowance of replacement power costs for this outage and that PSNH revise its contractor relationships so that it is clear that PSNH instructions must be followed otherwise contractual penalties will be imposed.

The next outage is Outage Schiller CT-1-A which occurred on 1/17/08 as identified in Exhibit MDC-7. The unit failed to start when called on by the ISO. Low air pressure "maxed out" the pressure speed timer. The air compressor was undergoing repairs in

Germany and air pressure was taken from Schiller Station to start the unit. To increase efficiencies and reduce losses, the air pressure at Schiller was reduced to 250 pounds from 500 pounds which is insufficient to start the unit. The time/speed setting was increased to allow more time to bring the unit up to required speed before it caused alarms to go off. Schiller Station set up a team to evaluate this unit including maintenance practices and problems occurring at this unit. PSNH notes that the recommendations of this team were implemented in 2009.

This outage occurred for reasons identical to the outage described in the review of the 2007 SCRC (Outage Schiller CT-1-H on 12/13). Liberty recommends that the replacement power relative to this outage be disallowed. The decision to reduce air pressure at Schiller either had no review or a review at such a level that the combustion turbine was not considered. Even a cursory review should have raised the question of adequate air pressure for starting the combustion turbine. In any case, the occurrence of the identical outage one month later should have received a PSNH response including the lessons learned from the previous outage.

The last outage that Liberty finds unreasonable is Outage Schiller CT-1-B which occurred on 3/3/08 as identified in Exhibit MDC-7. The unit was scheduled for its annual inspection starting 3/8 with the ISO (effectively 3/10 for normal work days). The unit was mistakenly taken out of service a week early while the Schiller Station was in an outage for Unit #5. While reassembling the unit, the replacement of a damaged igniter extended the outage. The igniter was damaged during reassembly of the unit when a shroud for the hot side of the burner cans was slid back over the igniter section of the combustion turbine to allow access to the burners cans. The exciters are somewhat delicate and located in close proximity to the shrouds. This type of damage has not been common over the almost 40-year life of the unit. Liberty views this incident as accidental. Once reassembled, the unit was returned to service. To prevent reoccurrence of taking the unit out on the wrong date, PSNH reviewed week beginning and week ending calendars as used by the ISO with maintenance personnel.

The time for the outage and outage extension above were 0.65 days and 0.78 days respectively. Liberty recommends that the replacement power relative to the early removal of the unit (0.65 days) be disallowed. Removal of the unit was not adequately communicated especially when the well established intent of outage scheduling at Schiller is to sequence unit outages for work force purposes. Operators should have known outage schedules and unit scheduling requirements. The outage time associated with the damaged igniters is considered accidental by Liberty.

Q. In addition to your recommendations regarding the recovery of outage costs, do you have other recommendations regarding your review of unit outages?

A. Yes, I do. The first additional recommendation relates to outages where PSNH is pursuing insurance, warranty claims or performance issues against the manufacturer. PSNH efforts are not complete and may not be complete until 2010 in some cases. The outages at issue are Outage MK-2-E (Inspection of the damaged HP/IP turbine), Outages Newington-1-C and Newington-1-D (Damaged exciter), and all outages with performance issues, claims, etc. associated with Schiller-5. Liberty's recommendations are specifically enumerated below.

Liberty recommends that replacement power costs for Outage MK-2-E be recovered in this proceeding, but notes that the total review is not complete. Liberty also recommends that the Commission provide an after-the-fact opportunity for review of PSNH's efforts to mitigate costs to customers in this outage to complete the review.

Liberty recommends that replacement power costs for Outages Newington-1-C and Newington-1-D not be recovered by PSNH in this proceeding. Liberty also recommends that the Commission provide an after the fact opportunity for review of PSNH's efforts to mitigate costs to customers in this outage.

Liberty recommends that PSNH recover replacement power costs for the outages related to warranty and performance issues of Schiller Unit 5 in this proceeding. Liberty also recommends that PSNH prepare a report of all such Alstom warranty and performance issues that describe the issue involved PSNH's efforts for resolution with Alstom, and the final resolution. Liberty further recommends that the report be filed by February 1, 2010 and updated in future SCRC reconciliation filings until all issues are resolved. Liberty further recommends that the Commission provide an after the fact opportunity for review of PSNH's efforts to mitigate costs to customers in these outages.

The second recommendation relates to the isophase bus duct failure at Wyman-4 due to malfunctioning heaters. Merrimack and Schiller stations do not have heaters in their isophase bus ducts due to their initial base load design and operation. Newington does have heaters and PSNH inspected them prior to the winter freeze and thaw cycles. Liberty recommends that due to volatile market conditions that can change the operation of both Merrimack and Schiller, that PSNH evaluate the need for heaters in their isophase bus ducts.

The third recommendation relates to National Electrical Safety Code required patrols of the 34.5 kV lines in rights of ways. In its explanation regarding Outage Canaan 1-F, PSNH stated that that patrols were limited to aerially thermographic inspection of 34.5 kV lines in rights of way due to constraints of declining Reliability Enhancement Program funding. Liberty understands that PSNH had agreed to perform inspections of all distribution facilities on a four year schedule as part of its 2006 REP plan. Liberty recommends that this issue be specifically addressed in the 2009 Reliability Enhancement Program contained in PSNH's current rate case.

The fourth recommendation relates to outages caused by trees that are outside of rights of way. Outages Canaan 1-E and Canaan 1-L were caused by trees which PSNH stated were outside of the right of way. PSNH further states that many of its older 34.5 kV lines in rights of way (1,600 miles plus) do not have language in the easements that allow PSNH to address "danger trees" outside of the right of way.

PSNH therefore does not address the outside of right of way danger tree issue. Liberty recommends that PSNH address danger trees that are outside of the 34.5 kV rights of ways, include identification of such trees in NESC required patrols, and identify where PSNH does and does not have the rights to remove danger trees. Liberty further recommends that this issue be specifically addressed in the 2009 Reliability Enhancement Program contained in PSNH's current rate case.

The fifth and last recommendation concerning outages relates to the number of outages at the hydro and combustion turbine units that appear to be due to protection mis-coordination. Many outages involve apparent mis-coordination between PSNH lower voltage generating units and the distribution system. PSNH has begun an analysis regarding settings etc. and suspects that some trip settings may be set too tight. PSNH also states that many of its small generating stations do not have regimented relay testing requirements by Northeast Power Coordinating Council or North American Electric Reliability Corporation as they are not considered bulk power facilities, however; PSNH does perform relay testing on all units. PSNH further states that relay settings have not changed at its small generating stations since the early 1980s. While new generation coming onto the PSNH system undergoes an interconnection analysis that reviews coordination, no such analysis has been done for PSNH's own units. Liberty recommends that PSNH perform interconnection analyses for all combustion turbines and hydro units connected to the lower voltage PSNH system. The Merrimack combustion turbines and Smith hydro are connected to the 115 kV system and such mis-coordination does not exist. Liberty further recommends that PSNH establish an appropriate relay testing program for all combustion turbines and hydro units. Liberty suggests that PSNH complete this work expeditiously and file a report of its actions to date and completion schedule concurrent with the next SCRC filing.

Q. Are there recommendations you have for PSNH not related to the specific review of the unit outages?

A. Yes, there are three general recommendations that Liberty has to offer in that regard. The first general recommendation relates to the many outages that relate to inspection and refurbishing of major turbine and generator parts off site. When PSNH sends a major generator/turbine component off site for inspection and repair, it is exposed to major emergent work issues that all but automatically become critical path components of the outage. Such components include the various HP, IP, and LP turbines and generator components. Such emergent work issues are especially significant for base load units in a market environment. Liberty recommends that PSNH perform an evaluation of procuring spare critical generator and turbine components or procuring industry arraignments that facilitate the same goal in order to reduce risks to customers for catastrophic failures of such components.

The second general recommendation relates to the first recommendation regarding the fact that major station components are sent off site. Transporting large pieces of equipment is a very complicated effort considering that each state may have different and conflicting requirements and restrictions. Lack of coordination in travel permits can often extend outage times because the components in transit are already on the outage critical path. Liberty recommends that contractual arrangements with manufacturers of major system components have travel plans in place and hold the manufacturer responsible for unnecessary transportation impacts on unit outages.

Lastly, with regard to the third general recommendation, Liberty understands that the manufacturers of generators and turbines are recommending longer times between inspection of their components. For example, manufacturer ABC recommends an inspection time of 10 years for its turbine that used to have a five year inspection cycle. Liberty is aware of multiple instances where older station components have failed in the later years of the manufacturer's new recommendations resulting in significant unplanned outages and additional outage costs charged to customers. Liberty recommends that PSNH not simply adopt unit manufacturer's recommendations regarding claims of extension of outage maintenance without first doing its own independent analysis tot support such actions as prudent.

Q. What was the result of your review of the eight Additional Recommendations included in the Stipulation and Settlement Agreement in Docket DE 08-066?

A. The eight Additional Recommendations listed in Section IV.c. of the Stipulation and Settlement Agreement in synopsis form are:

1. Review foreign material exclusion policy and modify as required. Add more accountability to the policy.

2. Evaluate the need of a roving person to ensure practices, procedures, and safety requirements are met.

3. Review existing equipment inspection schedules for adequacy and evaluate original equipment that does not have a set inspection to determine if one should be included.

4. PSNH should not rely exclusively on aerial patrols for lines in rights-of-way.

5. Consider moving check valves and exercise care in the placement of check valves.

6. Identify locations at generating stations where the switching function is performed by two systems with different configurations.

7. Check system lightning protection in the area of Canaan hydro station.

8. Review existing distribution protection setting and make changes to minimize impact to local generation and minimize impact to local generation with make future protection settings.

Liberty reviewed the PSNH action responses to those recommendations. Liberty accepts PSNH's response to Additional Recommendations #1 through #3 and #5 thorough #7 as a good faith effort to objectively review the issue and make appropriate adjustments in its operational practices. Additional Recommendation #4 centered on PSNH performing ground patrols of its 34.5 kV lines in rights of way. No patrols were initiated, but PSNH wishes to address this issue in its current rate case. Liberty specifically addresses this issue above. Additional Recommendation #8 regarding potential mis-coordination with units on the lower voltage PSNH system is also addressed above. Liberty considers the eight additional recommendations in the DE 08-066 Stipulation and Settlement Agreement addressed to its satisfaction if Liberty's further recommendations here regarding Additional Recommendations #4 and #8 above are adopted.

Q. What was the result of your review of the unit availabilities and capacity factors of the PSNH units?

A. As stated above, the base load units have run well especially considering that many factors have tended to reduce unit output and lower performance metrics. Recently, PSNH has been extending the period in which long maintenance outages are performed on some of its units. Major overhauls are now conducted on different cycles, depending on the unit and its maintenance requirements.

Liberty made the following observations regarding 2008 capacity and availability factors with planned outages removed from the calculations so that the different maintenance schedules do not skew the data.

Schiller 4 and Schiller 6 availabilities generally run about 95 percent with capacity factors of over 80 percent.

Unit 5 at Schiller had its boiler replaced in late 2006 with a wood fired fluidized bed boiler. This unit has different characteristics than the old coal fired boiler so Liberty makes no comparisons with historic operation. Liberty does note that in 2007, the first full year of commercial operation the unit had numerous startup and warranty issues which impacted the availability and capacity factors for the unit. In spite of new unit difficulties, Schiller 5 had an approximately 85 percent availability and an approximately 80 percent capacity factor for 2007. In 2008, further improvement was noted in that unit availability was approximately 90 percent and unit capacity factor was about 80 percent.

Newington maintained an availability of approximately 95 percent in 2008. Its capacity factor has fallen from 60 percent in 2003 to 40 percent in 2005, 10 percent in 2006 and 2007, and to approximately 3 percent in 2008. Its cost in relation to the market price is the reason for the decline.

Capacity and availability factors for Merrimack-1 have historically run at approximately 90 percent. Since it went to its two-year maintenance schedule in 2002, these factors dropped closer to 90 percent or below in the non outage years but have recovered to between 90 and 95 percent in both 2007 and 2008. Liberty believes that these results indicate that PSNH is adapting its maintenance operations to the new 2-year schedule.

The availability factor for Merrimack-2 has historically run at approximately 90 percent. The historical capacity factor runs about 85 percent. In the last few years including 2007, its availability factor has been 95 percent and its capacity factor has improved to over 90 percent. In 2008, both the unit availability and capacity factors were approximately 85 percent due to the problems associated with the new HP/IP turbine.

Q. Are there other observations you made with regard to the availabilities and capacity factors of PSNH generating units?

A. There is one. The capacity factor of Newington has dropped to approximately 3 percent in 2008. Information supplied by PSNH suggests that Newington cost millions more than it earned for customers in 2008. Such value could bring into question the continued operation of the unit from an economic viewpoint.

Q. What is your opinion of the continued operation of the Newington unit from an economic viewpoint?

A. I have none at this point in time because looking at the economics of plant operation in 2008 does not reflect the value of the plant over its 40 to 60 year life. In addition, the information provided by PSNH did not include the value of Newington as a hedge against the market. As Liberty understands the issue, such a market hedge arrangement has not yet been made and Liberty believes that it may be expensive. Also, units such as Newington mesh extremely well with the generation expansion plan envisioned by the region. The New England region is leaning towards increased energy production from renewable resources, namely wind. Wind power can fluctuate widely and within a short period of time. Fast reaction resources such as Newington have value in integrating those renewable resources into the power grid. Newington also has a dual fuel capability which must be factored into the evaluation. Lastly, the capacity and energy markets change very quickly. Liberty does conclude that this docket would not be the proper place to address the value of Newington to PSNH customers and suggests that if the subject is ripe for review that a separate proceeding be initiated that considers the complexities of valuing Newington going forward.

Q. What did you form as a conclusion when you reviewed the projected spending for capital projects and O&M at PSNH generating stations?

A. Liberty reviewed the 5-year capital and O&M budgets for Merrimack Station, Newington Station, Schiller Station, and the Hydro group, made the following general observations, and draw the following conclusions.

Capital

PSNH capital expenditures have been at an elevated level in the last few years and remain relatively high even after eliminating the Northern Wood Power Project and the Merrimack Clean Air components.

A peak in net capital expenditures (without wood and clean air projects) occurs at Merrimack Station in 2008 due to multiple major projects including the turbine replacement project.

The PSNH 5-year business plan calls for continued equipment replacement as required for reliable and efficient unit operations.

O&M

PSNH O&M expenditures have been at an elevated level for the last few years and remain relatively high in the 5-year business plan.

A peak in the O&M expenses occurred in 2008 at Merrimack Station which Liberty believes again centered around major projects including the turbine replacement project

The PSNH 5-year business plan calls for continued maintenance of equipment as required for efficient unit operations.

Liberty concluded that PSNH is spending and plans to spend sufficient funds for capital replacement projects and sufficient money for adequate maintenance to assure continued operation of its units consistent with good utility practice and with recognition of their age.

Q. Are there any other items you wish to discuss?

A. I only wish to list the data responses relied upon in the preparation of my testimony, in addition to the materials filed by PSNH, so they may be officially admitted into the record. Those data responses are attached following my exhibits and are:

Staff Set 01

Data Responses 9 through 33.

Staff Set 02

Data Response 5.

OCA Set 01

Data Responses 9 through 25.

OCA Set 02

Data Responses 9 through 15.

Tech Set 01

Data Responses 1, 2, 4, and 5.

Tech Set 02

Data Response 5.

Q. Does that conclude your testimony?

A. Yes, it does.

RESUME OF MICHAEL D. CANNATA, JR., P. E.

Michael D. Cannata, Jr., P. E.

Areas of Specialization

Investigations of safety, reliability, and implementation of public policy in the electric and gas industries; investigations of unit outage and system outage causes, electric utility operations and planning; bulk power system planning; interconnections; transmission system design.

Relevant Experience

Innovative Alternatives, Incorporated

- Evaluated the appropriateness of the proposed Storm Fund Adjustment Factor and the Inspection and Maintenance Program Basis Service Adjustment Mechanism for Power Option, a load aggregator in Massachusetts Electric Company's first delivery rate case in 10 years.

The Liberty Consulting Group

- Lead consultant for Liberty's review of the transmission system of Nova Scotia Power for The Nova Scotia Utility and Review Board. Liberty's review examined (1) system maintenance, inspection, structural design, materials, staffing, and related matters, (2) system planning, operations, system design, lessons learned, and other matters, and (3) utility communications, call center operations, staffing, outage management system, lessons learned, and related matters after the collapse of multiple transmission lines in November 2004.
- A lead investigator in the management audit of Consolidated Edison Company of New York reviewing adequacy of multi-area transmission planning and resource adequacy within the multi-area system for the New York Public Service Commission.
- Lead investigator reviewing the adequacy of system interconnection requirements of a major renewable fuel resource for the Nova Scotia Utility and Review Board.
- Technical advisor to the Maine Public Utilities Commission, Vermont Public Service Board, Kentucky Public Service Commission, and the District of Columbia Public Service Commission regarding the public necessity and convenience for a multitude of 345 kV, 230 kV, 161 kV, 138 kV, 115 kV, and 69 kV facilities.

- A lead investigator monitoring Commonwealth Edison's implementation of T&D system reliability improvement recommendations resulting from major system outages for the Illinois Commerce Commission.
- A lead investigator in the prolonged outage of Ameren T&D facilities following severe wind and ice events in 2006 for the Illinois Commerce Commission.
- A lead investigator monitoring Ameren's implementation of T&D system reliability improvement recommendations resulting from major system outages for the Illinois Commerce Commission.
- A lead investigator in the investigation of transmission grid security in Illinois after the August 2003 blackout for the governor's blue ribbon committee.
- Lead investigator reviewing the operation and outage of the fossil power plants of Arizona Public Service Company for the Arizona Public Service Commission.
- Lead investigator reviewing the operation and outage of the fossil power plants of Duke Energy – Ohio for the Ohio Public Utilities commission.
- A lead investigator in the in-depth root cause analysis of a fire at a major Commonwealth Edison substation for the Illinois Commerce Commission.
- Lead investigator of the reliability of the T&D systems of four electric utilities in Maine.
- Served as a lead investigator in the review of distribution and transmission practices at Alabama Power and Georgia Power Company.
- Advisor for the New Hampshire Public Utilities Commission in the merger of National Grid and Key Span and the sale of Verizon assets to Fair Point Communications.
- Served as lead investigator in prudence reviews of major fossil and nuclear plant outages for the New Hampshire Public Utilities Commission.
- Served as the principal technical and analytical member in the Seabrook nuclear unit sale team acting for the New Hampshire Public Utilities Commission.
- Investigated the causes of overlapping unit outages at a major Reliant generation facility.

New Hampshire Public Utilities Commission - Chief Engineer

- Managed a professional staff of engineers and analysts engaged in investigations regarding safety, reliability, emergency planning, and the implementation of public policy in the electric, gas, telecommunications and water industries.
- Prime architect of the settlement between the State of New Hampshire and Public Service Company of New Hampshire (PSNH) that ended years of litigation and allowed state-wide competition in the electric industry to proceed.
- Investigated the operation and outages of the fossil and nuclear facilities of the Public Service Company of New Hampshire.
- Advisor to the Commission on utility system and operational issues including those of alternative energy generation.
- Decision-maker on the Site Evaluation Committee responsible for siting major electric and gas production and transmission facilities.

- Sat as decision maker at the New Hampshire Office of Emergency Management's Emergency Operations Center.
- Re-drafted the state's Bulk Power Siting Statute and facilitated resolution of widespread legislative tensions.
- Instrumental in achieving quality of service levels among the highest in Verizon's service territory.

Public Service Company of New Hampshire (PSNH)

- As Director - Power Pool Operations and Planning, PSNH
  - Responsible for the operation and dispatch of PSNH transmission and generation facilities through the New Hampshire Electric System Control Center.
  - Core participant in the merger/acquisition team activities culminating in the corporate reorganization of PSNH. Recognized and developed a successful employee retention program used during the acquisition.
  - Core Task Force Member for the DC electrical interconnection between Hydro Quebec and the New England Power Pool.
  - Developed real time integrated transmission system loading capabilities for the New Hampshire Electric System Control Center.
  - Represented PSNH at all major relevant national and regional reliability organizations including:
    - New England Power Pool
      - System planning Committee
      - System Operations Committee
      - All technical planning and operations task forces conducting regional and inter-regional studies and analyses
    - Northeast Power Coordinating Council
    - Joint Coordinating Council
    - Edison Electric Institute
      - System Planning Committee

- As Director - System Planning/Energy Management, PSNH
  - Coordinated the company's capital planning requirements for generation and transmission. Integrated its load forecasting and energy management activities.
  - A lead participant in the development and implementation of response strategies addressing the negative financial impacts associated with the proliferation of non-utility generation.
  - Ensured that the interconnections of non-utility generation met utility reliability requirements.
  - Re-designed the corporate budgeting system to allocate available resources by economic and need prioritization.
  - Driving force in re-directing corporate economic evaluations towards competitive business techniques.

- As Manager - Computer Department and System Planning, PSNH
    - Responsible for the Engineering Division's computer applications support and transmission system planning functions.
    - Principal in the development, design and implementation of the first-in-the-nation application of 345/34.5 kV distribution. Resolved daytime corporate-wide computer throughput logjam.
    - Integrated the Engineering Department's computer applications into the corporate computer organization.

Education

M.B.A., Northeastern University - 1975
M.S.E.E., Power System Major, Northeastern University - 1970
B.S.E.E., Power System Major, Northeastern University - 1969

Registration

Registered Professional Engineer - New Hampshire #5618

2008 Capacity/Energy Planning

Background

PSNH retains load serving responsibility for customers who have not selected a competitive supplier. PSNH's monthly peak load for 2008 ranged from 1,066 MW to 1,621 MW, on-peak monthly energy ranged from 299 to 438 GWH, and off-peak monthly energy ranged from 270 to 350 GWH. The market supplied 31 percent to 63 percent of PSNH's monthly on-peak energy requirements and 15 percent to 54 percent of PSNH's monthly off-peak energy requirements in 2008. For the year, the market supplied 44 percent of PSNH's on-peak energy requirements and 29 percent of its off-peak energy requirements.

In 2008 and at summer ratings, PSNH owned approximately 528 MW of coal units at two stations, 419 MW of oil plants in two units, 65 MW of hydro plants from nine stations, 43 MW of wood fired generation in a single unit, and 83 MW of combustion turbine plants in five units. PSNH also purchases 20 MW of nuclear capability from a single unit, 42 MW from various PURPA-mandated purchases, and 10 MW from IPP buyout replacement contracts. The PSNH portfolio totals approximately 1,210 MW of summer capability (1,277 MW winter). In addition, PSNH receives monthly capacity credits from the Hydro Quebec interconnection. PSNH must meet its share of the Independent System Operator – New England (ISO-NE) monthly capacity requirement which ranged from 2,164 MW to 2,366 MW. The difference between PSNH resources and the ISO-NE monthly requirement must be made up by supplemental purchases. The market represented approximately 38 percent to 43 percent of PSNH monthly capacity requirements in 2008 and varied from 826 MW to 1,013 MW.

Load requirements remained unpredictable in 2008. On January 1, approximately 50 MW of PSNH large customers were taking market supply or performing self supply. This load equivalent value rose in the month March to 75 MW. From June 1 through the end of September, large customers taking market supply or performing self supply dropped to approximately 25 MW. From the end of September through December, self supply customers rose to 125 MW. For 2008, the energy related to customer migration totaled 321 GWH compared to the PSNH forecast of 254 GWH.

During 2008, the NU system employed 16 FTEs (full-time equivalents and up from 14 in 2007) in the Wholesale Marketing Department with 4.75 FTEs allocated to PSNH and unchanged from 2007. The remaining 11.25 FTEs are allocated to the other two NU subsidiaries that do not have load-serving responsibilities. By function, 1.75 of the 2.00 Bidding and Scheduling FTEs, 2.00 of the 4.00 Resources Planning/Analysis FTEs, 0.50 of the 2.00 Energy and Capacity Purchasing FTE, none of the 3.00 Standard Offer and Default Service Procurement FTEs, none of the 3.00 Contract Administration FTEs, 0.25 of the 1.00 Administrative Support FTE, and 0.25 of the 1.00 Management FTE are allocated to PSNH. Since June 2003, PSNH has had on site full time capacity/energy planning personnel in New Hampshire dedicated to New Hampshire power supply. From an organizational viewpoint, the New Hampshire position reports to a Connecticut manager. The New Hampshire power supply person has accepted another position but is currently filling in until PSNH can fill the position. PSNH states that the new individual may be based in New Hampshire or may be based in Connecticut based on the preference of the individual.

To meet its load responsibility, PSNH requires supplemental on-peak and off-peak (defined by ISO-NE as weekends, holidays, and weekday hours 1-7 and hour 24) purchases that change hourly and vary from 0 MW to 400 MW on peak to 0 MW to 600 MW off-peak as Newington is not economic off peak (plus reserves for capacity purchases) depending on the day of the week and month. Liberty considers these requirements to be "fixed," as PSNH's requirement is based on no contingencies occurring but does include planned unit maintenance. These requirements are increased if any of the above generation is unavailable when needed to serve load or if loads are higher than planned due to variation in the weather or customer migration. Likewise, these requirements are reduced when loads are less than planned due to variation in the weather or customer migration. Liberty considers this portion of the energy supply to be "variable."

In general, PSNH supplemented its own generation with monthly, weekly, and daily bilateral purchases to meet the "fixed" portion of its supplemental on-peak requirements and used the ISO-NE spot market combined with daily bi-lateral purchases to meet the "variable" portion of its supplemental requirements. The table below shows how PSNH on-peak and off-peak energy requirements have been supplied by its own resources and the bilateral and ISO-NE spot markets. Of note is the increasing reliance on market energy generally due to load growth through time. Actual weather and major unit outages that do not occur every year can also alter these percentages.

Percent Supply of PSNH Energy Requirements from PSNH and Market Sources

	PSNH Owned Generation (Percent)		**Bilateral and Spot Energy (Percent)**	
	On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**
2004	83	90	17	10
2005	74	85	26	15
2006	67	80	33	20
2007	66	80	34	20
2008	56	71	44	29

The following table shows how PSNH units and the markets supplied PSNH energy requirements for 2008.

Percent of PSNH 2008 On-Peak and Off-Peak Energy Requirements Supplied by PSNH and the Markets

	On-Peak (Percent)	Off-Peak (Percent)
Merrimack and Schiller	41	54
Hydro	5	6
Vermont Yankee	2	2
IPP's	6	7
Buyout Contracts	1	1
Newington and Wyman	2	1
Combustion Turbines	0	0
Bilateral Purchases	38	19
ISO-NE Spot Purchases	6	10

The following table depicts PSNH's historical market purchases and their source by percent.

Historical PSNH Supplemental Purchases and Source

	Sup. Purchases (GWH)	LT Bilateral (%)	ST Bilateral (%)	ISO-NE Spot (%)
On-Peak				
2004	900	52	22	26
2005	1,424	83	4	13
2006	1,815	85	10	5
2007	1,642	78	9	13
2008	2,046	81	7	12
Off-Peak				
2004	431	0	33	67
2005	847	79	3	18
2006	1,106	79	6	15
2007	945	73	5	22
2008	1,210	64	5	31

2008 Energy Market

In the first quarter of 2008, price volatility dominated the marketplace. Gas varied in price from \$8 to \$18 per MMBTU or 8 cents to 18 cents per kWh assuming a 10,000 BTU/kWh heat rate (Newington), and #6 oil remained stable at approximately \$11.00 per MMBTU or 11.0 cents per kWh assuming a 10,000 BTU/kWh heat rate. These prices produced an on-peak bilateral energy market in New England that varied from 7 cents to 14 cents per kWh during the same time period.

Stability returned to the market in the second quarter of 2008 but with increasing costs. During that period, gas rose from \$8 per MMBTU to \$14 per MMBTU or 8 cents to 14 cents per kWh assuming a 10,000 BTU/kWh heat rate, and #6 oil rose from \$11 to \$17 per MMBTU or 11 cents to 17 cents per kWh assuming a 10,000 BTU/kWh heat rate. These prices produced an on-peak bilateral energy market in New England that generally varied from 9 cents to 21 cents per kWh during the same time period.

In the third quarter of 2008, market volatility subsided and prices fell. Gas dropped to approximately $8 per MMBTU or 8 cents per kWh assuming a 10,000 BTU/kWh heat rate, and #6 oil dropped to $8 per MMBTU or 8 cents per kWh assuming a 10,000 BTU/kWh heat rate. These prices produced an on-peak bilateral energy market in New England that generally dropped from 18 cents to 8 cents per kWh during the same time period.

In the fourth quarter of 2008, gas price was stable at $8 per MMBTU or 8 cents per kWh assuming a 10,000 BTU/kWh heat rate until December when it spiked to $13 per MMBTU (13 cents per kWh), and #6 oil dropped from $13 to $6 per MMBTU or 13 cents to 6 cents per kWh assuming a 10,000 BTU/kWh heat rate. These prices produced an on-peak bilateral energy market in New England that generally varied from 6 cents to 8 cents per kWh.

In 2008, PSNH relied on the market for a significant portion of its energy requirements. Loads generally were lower than forecast and up to 125 MW of large customers met their needs from the market or self supply, resulting in a reduced supplemental purchase requirement. Although market prices were high during much of the year, market prices were lower than PSNH costs during most of the fourth quarter. PSNH continues to be susceptible to both market price volatility and to fluctuations in the supplemental purchase volume created by changing economic conditions and the degree to which customers migrate to and from competitive supply options. Market price volatility would be expected to increase as ISO-NE loads and sources come more into balance in 2009 and beyond.

PSNH Supply Approach

Historically, PSNH has altered its approach to supply procurement each year as it has gained market experience. In the summer of 2005, PSNH continued to cover its position and purchased blocks of bilateral power for 2006 to bring stability to pricing and to limit potential under recoveries in every month rather than just the peak months and months of unit outages as was done for 2004. PSNH also supplemented its bilateral purchased for July and August in June 2006. In addition, PSNH did more hedging in 2006 for both on-peak and off-peak load periods to better reflect the forced outage rates of the coal units. In 2007, PSNH intended to establish a fixed annual energy service rate that is subject to minimal under-recovery or over-recovery. PSNH established its monthly purchase targets in the first quarter of the year and made a series of purchases of bi-lateral energy through November to cover these targets. In addition, PSNH purchased short term bilateral energy to cover forced outages and the high load periods. All other energy was either procured from its own units or from the spot market. In 2008, PSNH followed the same purchase pattern that it used in 2007 in order to minimize risks associated with market fluctuations.

In 2005, PSNH purchased 500 MW of its 2006 capacity requirement via an annual contract. The capacity market was scheduled to switch over to the new Forward Capacity Market (FCM) in October 2006, however, the switch over did not take place until December 2006. Uncertainty regarding the start date of the new FCM rules virtually precluded further capacity contracts after June 1, 2006. When the FCM transition period rules took effect in December 2006, each load serving entity was responsible for meeting its percentage of the total NEPOOL qualified capacity resources. NEPOOL qualified capacity resources are reduced by their individual forced outage rates (unforced capacity). The seasonal capability of PSNH units is also discounted for their forced outage rate to meet its percentage of the NEPOOL supply obligation.

The FCM took effect in December 2006 and was in full effect for 2007 and beyond. Under those rules, PSNH is billed at the transition capacity rate of $3.05 per kW-month through May 2008 and $3.75 per KW-month from June through December for its 6.00 to 6.37 percent share of the 34,586 to 38,212 MW of qualified unforced monthly capacity in ISO-NE or 2,164 to 2,366 MW per month less the value of its own resources. The ISO-NE transition rates produced a bill for $93.0 million for capacity and PSNH unit capacity produced a $55.2 million credit leaving PSNH with a $37.8 million capacity cost for 2008.

PSNH conducts biweekly phone calls with generating station, fuels, operations, and bidding/scheduling personnel. Plant personnel keep capacity/energy planning informed of impending developments at the plants. PSNH views Newington as the key unit on its system as all other owned units are hydro, coal, wood, or long-term resources that are almost always economic or must take contracts. The net monthly on-peak energy requirements of PSNH were 110 to 213 GWH and their monthly off-peak energy requirements were 46 to 151 GWH. The incremental energy needs from the market are determined by the actual weather that occurred, not the forecasted average weather in the energy forecast and actual unit operation.

PSNH covered major outages and known shortfalls by executing a series of monthly bilateral forward purchases from April 2007 through November 2007 for the January 2008 through December 2008 period. Monthly blocks of power were bought that closely matched the forecasted energy requirement. Additional monthly purchased were made throughout 2008 to address exposure and the reduced utilization of Newington.

Purchases were based on monthly analysis where PSNH modeled hourly forecasts by month including a hydro schedule, hourly load forecast, IPP forecast, and its own resources. PSNH modeled its own resources as follows. Combustion turbines and Wyman #4 were not modeled as they have extremely low capacity factors and the market price tends to mimic their cost when they do run. Coal units have planned outages specifically modeled and are derated to their annual forced outage rate for the periods in which it runs. PSNH also discretely models the short planned reliability outages. Newington costs were modeled as the projected market cost of oil corrected for SOX and NOX calculations and at a full load dispatch rate. If the cost of Newington was lower than the blocks of power to be purchased, Newington was run as loaded for that block. The remainder of the energy requirements was supplied by the spot market.

Financial Transmission Rights (FTRs) are needed on-peak to protect against congestion pricing in the pool. In essence, one trades a known price for a potentially high variable congestion price. These rights are limited by actual system capability, function much like a hedge, and bring certainty to the price of generation with regard to congestion. FTRs are purchased between the major PSNH stations (Seabrook, Vt. Yankee, Mass. Hub, Merrimack, Newington (For the months it is expected to run), and Schiller known as the source locations) and the New Hampshire load zone (sink location). In 2008, PSNH purchased 7,818 MW-months of on-peak FTRs and 5,385 MW-months of off-peak FTRs. The table below shows PSNH's historical FTR purchases, their value regarding avoided congestion costs, and their cost to PSNH customers.

PSNH Historical FTR Costs and Savings

Year	Auction Cost (Thousands)	Avoided Congestion Costs (Thousands)	Net Cost (Thousands)
2003	414	488	74
2004	1,341	1,417	76
2005	777	896	119
2006	301	133	(168)
2007	973	1,133	160
2008	827	237	590

PSNH bilaterally purchased 1,795 GWH of on-peak energy and 831 GWH of off-peak energy. PSNH also spot purchased 252 GWH of on-peak energy and 380 GWH of off-peak energy. PSNH made two types of sales into the New England market. It sold 2.1 GWH of on-peak energy and 19 GWH of off-peak energy from surplus generation from owned units that netted $22 thousand above cost. PSNH also sold unneeded bilateral energy on the spot market because loads failed to materialize as or when expected. PSNH resold 167 GWH of on-peak bilateral energy at a price of $87 per MWH and 125 GWH of off-peak bilateral energy at a price of $63 per MWH. These sales resulted in a gain on on-peak energy sales of $437 thousand and a loss on the sale of off-peak energy of $215 for a total net gain of $222 thousand.

To provide certainty of cost and to limit potential under recoveries, PSNH purchased most of its bilateral energy via fixed price contracts. PSNH purchased its 2008 energy in the months after the run up in the price of fuel. In addition to market fluctuations, PSNH had approximately 25 to 125 MW of its largest customer sign contracts with retail suppliers representing 321 GWH annually or 11 to 50 GWH per month.). Customer migration can swing annual supplemental purchases significantly, especially in the lower load months.

Projected Unit Capacity Factors

The table below shows the historical capacity factors and the projected capacity factors used for the 2007/2008 period.

Actual and Projected Annual Capacity Factors for PSNH Major Units
(Annual Generation/Winter Rating/8760)

	Actual Capacity Factor - Percent								Forecasted Percent
	2001	2002 (1)	2003 (2)	2004	2005	2006	2007	2008	2008
Merrimack-1	81.6	74.7	93.3 (3)	86.8	90.6 (3)	80.6	95.7	79.8	74.9
Merrimack-2	72.7	75.7	73.9	80.3	79.1	84.1	82.9	72.8	71.9
Schiller-4	66.5	65.4	73.9	73.7	76.5	71.1	84.2	78.5	72.9
Schiller-5	59.3	68.2	73.5	74.0 (4)	72.4 (4)	42.0(5)	76.7	79.8	80.4
Schiller-6	62.8	71.6	75.1	76.6	81.4	77.6	74.6	80.7	75.3
Newington	12.6	19.0	55.9	50.3	33.5	8.0	9.3	3.3	4.9

(1) - Seabrook not in PSNH mix for November and December.
(2) - First full year Seabrook not in PSNH mix.
(3) - No unit overhaul in this year.
(4) - Very minor outage this year due to wood conversion.
(5) - Coal to wood boiler conversion project.

PSNH based the 2008 projected capacity factors by explicitly modeling planned annual maintenance and consultation with plant personnel. Short term planned reliability outages were also discretely modeled and are not included in the overall annualized forced outage factor. The table clearly shows that PSNH base load units performed better than forecasted.

Evaluation

Liberty reviewed the capacity/energy planning testimony filed by PSNH, conducted an on site interview with knowledgeable personnel responsible for the capacity/energy planning function at PSNH, submitted follow-up data requests, and reviewed detailed backup information of the summary results supplied by PSNH. Liberty concluded that the PSNH filing is an accurate representation of the process that took place in 2008 and that PSNH made sound management decisions with regard to capacity and energy purchases in its market environment. Liberty also concluded that the capacity factor projections used in its purchase projections were reasonable.

Merrimack Outages For 2008

Merrimack-1

The following outages occurred at Merrimack-1 during 2008. The major project for this unit was the replacement of the HP and LP rotors during the annual overhaul.

A - (Outage Report OR-2008-02)
1/7 – 2.9 days
The unit was taken off line for this planned outage on a Monday due to the low cost of power as projected by bidding and scheduling. The unit was on line for 105 days and required an air heater wash. This is a common outage for this unit after approximately 3 months of continued operation. If the unit is out of service for other reasons, the air heaters are washed at that time so that a special unit outage is not required.

PSNH planned to install new enamel cold end air heater baskets in the fall overhaul (Outage E below) to lengthen the time between wash cycles. The enamel coating retards the buildup of ash on the air heaters.

B - (Outage Report OR-2008-08)
4/25 – 3.6 days
This was a planned maintenance outage taken to wash the air heaters from continued operation since the January 10th air heater wash.

C - (Outage Report OR-2008-10)
6/6 – 3.1days
The unit was taken off line to repair 4 reheater tube leaks. The leaks were repaired and the unit returned to service. PSNH noted that non-destructive examination of this area of the boiler found no issues in 2006. However, non-destructive examination during the fall 2008 outage (Outage E below) indicated thinning of reheater tubes requiring replacement in 2010.

D – (Outage Report OR-2008-12)
8/20 – 2.1 days
The unit was taken off line due to a screen tube leak. A large clinker (buildup of solidified ash) hanging from the secondary super heater fell and damaged the tube screen clip. The clip cracked and the crack propagated to the screen tube causing the tube to fail. PSNH noted that replacement of some of the screen tubes has been scheduled over the next two overhauls.

E

9.9 – 49.6 days

This planned outage was taken to perform the 2008 overhaul for the unit. The outage schedule critical path was dictated by the removal, repair, and re-installation of the HP and LP rotors. The outage had an ISO outage window of 56 days. The PSNH outage schedule which is set on the aggressive side was scheduled for 49 days with the actual outage coming in at 51 days or 49 hours behind PSNH schedule.

Siemens entered into a contractual arrangement with PSNH to have the rotor returned by 10/18, essentially locking in the critical path to that point in time. After 10/18, the schedule became exposed to delays and gains based on daily progress during the outage. Siemens was able to ship the HP rotor one day earlier than contractually obligated to do so but the LP rotor was shipped 8 hours later than planned due to difficulty in Siemens receiving travel permits for the permit loads (Specific travel restrictions which may vary from state to state).

Once the HP and LP rotors were on site, items such as the grinding of the generator collector rings which requires the turbine to be in place and rotating on turning gear and other items that emerged as emergent work in the close out work sequence caused the outage to exceed schedule by about 2 days. The bulk of the outage extension was due to the grinding of the generator collector rings (19 hours).

F - (Outage Report OR-2008-14)

10/31 – 2.1 days

The unit tripped when the P-12 breaker opened during the start up of the main fire pump motor. The P-12 breaker feeds the circulating water pumps. The P-12 breaker was replaced as part of the switchgear replacement of two 4.16 kV load centers during the annual overhaul in Outage E above. Investigation found that the relay setting to the screen house and fire pumps was set too low by the vendor who used an incorrect current transformer ratio in setting the relay.

This problem was a vendor quality control problem as PSNH supplied the correct information to the vendor. PSNH had all relay settings made by the vendor checked again by the vendor and all were found to be correct. The vendor has also included current injection to each breaker to confirm correct current transformer ratios as part of its new equipment start up procedures.

Prior to coming off line for this outage, a boiler leak was evident. The outage was extended to repair 2 boiler wall tube leaks. Upon startup, the condensate pump mechanical seal failed requiring replacement and extended the outage further. After the seal was replaced, the unit returned to service.

G – (Outage Report OR-2008-16)

11/25 – 4.0 days

The unit was taken off line to repair a screen tube leak in the floor of the boiler. The failed tube was not in the section of screen tubes that were replaced during the overhaul in Outage E above, rather was located behind refractory and was not identified during the non-destructive examination performed during the overhaul. The screen tube was repaired and the unit returned to service.

H
12/5 – 0.7 days
This outage was required because of a noisy 1B air heater drive. During the annual overhaul (Outage E above), both air heaters were replaced. The spare air heater drive was installed in heater 1A based on maintenance records and the 1A drive was sent out to be rebuilt. PSNH monitored the noise in the 1B drive, expedited the rebuilding of the 1A drive, and took this outage to replace the 1B gear box. The gear box was replaced with the rebuilt drive and the unit returned to service.

I
12/15 – 0.3 days
The cyclone 1A and 1C cyclone blast gates were replaced during the annual overhaul. The blast gates are located above the cyclone burners and are designed to prevent the fires in the cyclones from backing up into the coal feeders. When cleaning coal pluggage, the 1A blast gate would not operate in either the manual or automatic mode, requiring the unit to come off line. Modifications were made to the 1A cyclone blast gate and the unit returned to service. During a subsequent outage, modifications were made to the 1C cyclone blast gate.

Merrimack-2

The following outages occurred at Merrimack-2 during 2008. The major projects for this unit were the replacement of the generator rotor, upgrade of the HP/IP turbine, air heater tube replacements, secondary superheater inlet bank replacement, and the replacement of the boiler floor.

A - (Outage Report OR-2008-03)
1/30 – 5.3 days
The unit was taken off line due to a secondary superheater leak in the inlet bank that damaged two adjacent tubes. The damage was such that 124' of tube needed replacement and scaffolding was required, thereby lengthening the outage. Two water tube leaks in the 2B and 2C cyclones and a furnace wall tube leak were also repaired. The unit returned to service without incident. Note: the secondary superheater inlet bank was replaced during the annual overhaul in Outage C below.

B – (Outage Report OR-2008-06)
3/2 – 4.5 days
The unit was taken off line due to a secondary superheater leak in the inlet bank. Investigation revealed that the failed tube had damaged 4 tube U-bends in the secondary superheater inlet pendent requiring their replacement. In addition, the failed tube damaged three adjacent tubes with steam cuts. Two water tube leaks in the 2C cyclone

and four furnace wall tube leaks were also repaired. The unit returned to service without incident. Note: The secondary superheater inlet bank was replaced during the annual overhaul in Outage C below.

C

4/1 – 50.8 days

This planned outage was taken to perform the annual over-haul of the unit, extensive generator stator inspection, air heater tube replacement, boiler floor replacement, secondary superheater inlet bank replacement, and the installation the new more efficient HP/IP turbine. The outage was scheduled with an ISO window of 63 days, but was aggressively internally scheduled to last 50 days. The actual outage ran duration of 52 days. The critical path throughout the majority of the outage was the replacement of the hot side air heater tube replacement project consisting of approximately 28,000 tubes consisting of multiple sections each. Only two significant schedule changes occurred during the outage. The first was a 23 hour delay to tighten the generator stator core, however, that time was made up by changes made to the generator stator program. The other areas of delay were attributed to high winds impeding boiler sealing (10 hours) and the boiler hydro test and delays due to boiler leaks which were not known until the boiler hydro test was performed (33 hours). These items accounted for virtually all of the schedule delay for the overhaul.

Liberty made some suggestions of potential for improvement during the outage such as listing crane departure dates on the update reports and having weekend updates conducted during the outage. PSNH quickly reviewed the suggestions and has included crane departure dates in its update report and has increased the frequency of outage updates during the last two weeks of a major outage when the dynamics of the outage increase.

D

5/22 – 0.8 days

The unit had just returned to service from its annual overhaul in Outage C above. An operator noticed that one of the disconnect switches (G-201) for the generator main breaker was red hot and removed the unit from service. The NU transmission department performs thermographic inspection of this equipment twice a year and additional inspections upon request. The G-201 disconnect was replaced in 2006 and last thermographed in 2/08 with no anomalies noted. The switch was found to have poor contact, was replaced, and the unit returned to service.

E – (Outage Report OR-2008-11)
6/20 – 23.9 days
This outage was required to inspect the new HP/IP turbine to determine reasons why the unit failed to even achieve prior existing full load capability when returning from the annual overhaul in Outage C above. The installation of a new more efficient HP/IP turbine was supposed to increase output in the order of 10 MW.

During startup from the annual overhaul, full load was not reached. Siemens was called in and found no noise problems, no vibrations, no overheat problems, no oil problems, good chemistry, proper temperatures, and proper pressure differentials. PSNH believed that with no abnormal indicators, that a design problem existed with the new HP/IP turbine. Siemens determined that the best approach would be to leave the unit at 300 MW and not attempt to obtain a higher load level out of the unit until it could be inspected.

The unit ran at 300 MW until taken out of service for inspection during this outage. In the time between returning from service and this inspection outage, Siemens thoroughly checked all designs, materials, analyses performed, pedigree of materials, and their records to find a clue as to why the unit was not performing as it was designed to do so. No design or material deficiencies were found.

Inspection revealed foreign material was in and had passed through the turbine and had damaged the turbine blades. PSNH checked and inspected approximately 100 locations with a boroscope for foreign materials including the LP-1 turbine, LP-2 turbine, condensate and feedwater systems, boiler headers and tubes, and turbine piping. The inspection was broadened to include valves, pumps and heaters. Foreign material was found in the condenser hotwell, main boiler feed pump, condensate pumps, and deaerator. No foreign material was found in the boiler.

A vast array of vendors and specialists were brought in to perform inspections, cleaning, and corrective action for identified repairs.

In the investigation process, PSNH identified chrome throughout the foreign material and determined that the chrome was not plated off of the turbine. The foreign material was identified as shot blast material. There is no record or personnel knowledge of shot blast material ever being used at Merrimack Station indicating that the foreign material was introduced from vendor supplied material. Three possible sources were identified. The vendor of the HP/IP piping, BendTec, did shot blast their product and then applied a protective coating. The vendor for the 23 secondary superheater inlet bank pendants, B&W Mexico, did not use shot blast on either the inside or outside of the tubing, however, shot blast is used for other purposes in their facility. The tubing vendor to B&W Mexico, Bentler, does not blast tubes at all. The furnace floor was manufactured by B&W Miss., and was shot blasted externally. The tubing was supplied by MST who does not blast tubes at all. All vendors who used shot blast material supplied samples for analysis. Extensive and multiple analyses showed that all samples were consistent with the foreign material found in the HP/IP turbine. All piping received from all vendors was either inspected with a boroscope or blown out/vacuumed prior to installation, a long standing Merrimack Station requirement.

During its review, Liberty noticed that plywood is nailed to staging planks at most work locations. Liberty requested that the nails (called duplex nails because they have a double head for extraction) used for this purpose be analyzed for material content. PSNH analyzed the staging nails and found that they are made of low carbon steel, contain no chrome, and are very soft. There are two harness scales used in the industry, which are the Rockwell and Brinell hardness scales. A zero on the Rockwell scale is a 152 on the Brinell scale. The nails tested to a Brinell hardness of 100 while the shot blast tested to a Rockwell hardness of 44. Simply stated the hardness of the staging nails is below the Rockwell scale and could not be the foreign material.

In summary, no root cause for the path of the foreign material reentrance into the boiler has been identified, yet none have been ruled out including sabotage. Results are totally inconclusive.

The unit was cleaned and reconditioned or repaired as required. The unit returned to service and achieved a 320 MW load level at full load, its previous full load level. The 320 MW load was achieved with lower than full load steam flow indicating that the turbine was more efficient but that the remaining turbine damage prevented achieving a higher load.

A repair and replace option was considered. A new turbine would cost well in excess of $10 million and would take 2 ½ years to procure. In that time period, increased MW would not be available from the turbine. The repair option would replace all turbine blades in the HP/IP turbine so that the entire steam path was new. The decision was made to go with the repair option. The repair option would commence on 8/1/09 and last for 18 weeks. Note: If the upgrade was to produce a 10 MW upgrade, each dollar per MW that the Merrimack delivery price was lower than the market price would be about a $200,000 penalty to customers. Therefore, if Merrimack beat the market at $10/MWh, customers would be penalized approximately $20 million during the wait for a new turbine.

PSNH is pursuing insurance claims with its insurance carrier and performance issue with the vendor. These efforts are expected to continue into 2010. In addition, PSNH has strengthened and completely formalized its internal foreign material exclusion practice and reinforced foreign material exclusion requirements on contractors such as Siemens.

F – (Outage Report OR-2008-13)
9/19 – 4.6 days
The unit was removed from service due to high water usage resulting from tube leaks in the horizontal reheat section of the boiler. The primary leak damaged two other wall tubes. 14 other leaks and damaged tubes were found throughout the boiler. Repairs were made and the unit returned to service.

G
9/24 – 0.4 days
While returning to service from Outage F above, the unit tripped due to inadequate pressure in the 1st stage HP steam pressure sensing line. During the phasing of the unit, there is a short time period where the HP turbine needs to see transfer steam flow for minimum operation otherwise the unit will trip. The HP steam pressure sensing line is used as a proxy for HP turbine steam flow. Investigation revealed that the pressure switch sensing unit was faulty (would not trip with applied pressure), was replaced, and the unit was turned over to operations.

H – (Outage Report #14)
9/24 – 0.7 days
While returning to service from Outage G above, the unit again tripped due to inadequate pressure in the 1st stage HP turbine steam pressure sensing line. The sensing line was found to be plugged and would require a major outage to address. The location of the sensing line requires that the HP/IP turbine needs to be disassembled in order to either clean or replace it. Siemens approved using the HP/IP cylinder drain line as a proxy for the pressure of the HP turbine steam pressure sensing line. This line is in the same location as the plugged 1st stage HP steam pressure sensing line, so the same pressure reading is obtained. The unit returned to service without incident. The plugged 1st stage HP steam pressure sensing line will be replaced during the 2009 annual overhaul.

I
11/3 – 3.6 days
The unit was removed from service due to a tube leak in the horizontal reheat superheat section of the boiler. The primary leak occurred over time due to the failed tube rubbing and wearing against the economizer riser tube (Normal separation approximately 1/8 inch). PSNH states that this section of the boiler was visually inspected during the annual overhaul in Outage C above, no clip damage was noted, and the rubbing condition was not noted. PSNH further states that their review indicates an adequate amount of clip support for the tubes in this area.

Evaluation (Except for MK-2 – C and MK-2-E)

Liberty reviewed the outages above and found them either to be reasonable and not unexpected for these units and their vintage, or necessary for proper operation of the unit. Liberty concluded that PSNH conducted proper management oversight.

Evaluation for Outage MK-2 – C

There are two parts to the evaluation of the installation of the HP/IP turbine at Merrimack-2. The first evaluation answers the question if the conduct and management oversight of the outage itself was proper and the second is if it was in the customer's best economic interests to proceed with the replacement of the HP/IP turbine. This is Outage MK-2-C.

With regard to the question if proceeding with the HP/IP turbine was in customer's best interests, Liberty answers the question by performing its own economic analysis based on very conservative assumptions for information that was available at the time that a decision had to be made to proceed or not with the replacement of the HP/IP turbine for Unit 2. Those results are presented in Exhibit MDC-3A.

Merrimack 2 performed its last major and overhaul of the HP/IP turbine in 2003 and was scheduled perform the next inspection/overhaul in 2008 as the turbine was on a 5-year overhaul schedule. Siemens had determined in its 2003 blade condition report that the nozzle blocks (stationary blades) and first two rotating blade stages needed replacement in 2008.

In 2004, Siemens notified PSNH that it had developed a new HP/IP replacement turbine for its BB-43 frame machines (Merrimack 2 has a BB-43 frame). Siemens stated that the new turbine could go 10 years between inspection/overhaul eliminating a major unit outage and was markedly more efficient resulting in greater energy output. PSNH received budget grade estimates, determined that the project had about a 2-year payback, and bid out the project in early 2006 to ensure availability for the 2008 overhaul.

As noted above, Liberty performed its own economic evaluation on HP/IP turbine replacement economics. Liberty used much more conservative assumptions and found that under worst case conditions, that the project had an economic payback in the 12 to 13 year range. Such payback time periods demonstrate under the very conservative overlapping assumptions used suggest very strong project economics. In fact, the project economics are so in favor of the customer; Liberty would be raising questions of prudence if PSNH had not committed to pursue replacement in the 2008 outage window (earliest opportunity to do so) subjecting customers to added millions of added cost by their inaction. Liberty recommends recovery of replacement power costs for this outage.

Evaluation for Outage MK-2 – E

This outage would not have been required but for the performance issues related to the replacement of the HP/IP turbine at Merrimack-2. As noted above, PSNH is pursuing insurance claims with its insurance carrier and performance issue with the vendor. These efforts are expected to continue into 2010. Liberty recommends that replacement power costs for Outage MK-2-E be recovered by PSNH in this proceeding, but that the Commission provide an after the fact opportunity for review of PSNH's efforts to mitigate costs to customers in this outage.

Liberty Assessment of the Merrimack Unit 2 HP/IP Turbine Replacement in 2008

Liberty viewed the economic analysis done by PSNH to be a simplistic first cost analysis[1]. Many items are not considered when using a simplistic approach as PSNH did. Some items add to the economics of the project and some subtract from the economics of the project. The shortcomings of the analysis as noted by Liberty were that inflation was not considered, the time value of money was not considered, no sensitivity analysis was performed, project life was not included, and maintenance savings beyond the year of installation was not included. PSNH, however, did use conservatism in some of the study assumptions.

If Liberty were to redo the analysis using inputs as known today, such an analysis would be an economic review of project economics with hindsight. The Liberty approach was to take the inputs used by PSNH, use very conservative assumptions, and consider the factors mentioned above to look at what one might consider a worst case scenario with regard to the economics of the project. Liberty took this approach rather than to do a multitude of sensitivity analyses due to the strong economics exhibited by the project in the PSNH simplistic analysis.

Liberty discusses each input assumption here as used by PSNH or Liberty. They are as follows and are presented in tabular form further below:

- The capital cost of the project was estimated at $9 million. PSNH used this estimate and Liberty assumed a 33-1/3 percent cost overrun and used $12 million for the project cost.
- The expected increase in unit output was 6 to 10 MW. PSNH used the midpoint of 8 MW, while Liberty assumed the low end of the estimate of 6 MW.
- The estimated 2008 maintenance savings were $1.85 million. PSNH used this figure. Liberty considered this figure as relatively firm and used it also.
- The estimated 2013 maintenance savings were $2 to $4 million. PSNH did not include these savings in their analysis. Liberty looked at project economics both with and without 2013 budgeted maintenance savings of $1.45 million (2008$).
- No values were provided for 2023 maintenance savings in the second turbine inspection cycle. PSNH did not consider the second maintenance cycle and ignored these savings. Liberty assumed that at the 10-year inspection of the turbine that the manufacturer recommended returning to the standard 5-year maintenance cycle resulting in no further maintenance savings.
- PSNH estimated the market price of energy to be $81.75/MWH and used this value. Liberty assumed a 50 percent drop in market price from the outset of the analysis and used a 2008 value of $41.00/MWH.
- PSNH used a unit capacity factor of 0.75. This value is considered to be a low value and was also used by Liberty.
- PSNH used a value for capacity of $6.37/kW-Month. Liberty assumed a 50 percent drop in market price from the outset of the analysis and used a 2008 value of $3.20/kW-month.

[1] Data Request STAFF-01, Q STAFF-029.

- PSNH did not include maintenance savings generated in 2013 or beyond in its study. Liberty did its analysis with and without maintenance savings in 2013, but did not consider maintenance savings after that time. Liberty used a 20-year life.
- PSNH did not consider inflation in its analysis. Liberty used a 3.00 percent inflation factor.
- PSNH did not consider the time value of money in its analysis. Liberty used a NPV discount rate of 9.00 percent.
- PSNH did not consider the carrying costs (return, taxes, depreciation, etc.) of the investment in the new turbine. Liberty uses a value of 1.6 times the investment as a proxy for the NPV of the project over its life.

Assumptions	**PSNH**	**Liberty**
Cost of Project ($9.00 M)	$9.00 M	$12.00 M
Output Increase (6.0 to 10.0 MW)	8.0 MW	6.0 MW
2008 Maintenance savings ($1.85 M)	$1.85 M	$1.85 M
2013 Maintenance Savings ($1.45 M)	Did Not Use	$1.45 M and $0
2023 Maintenance savings (Same as 2013)	Did Not Use	Did Not Use
Market Price of Energy ($81.75/MWH)	$81.75/MWH	$41.00/MWH
Unit Capacity Factor (0.75)	0.75	0.75
Value of Capacity ($6.37/KW-Month)	$6.37/KW-Month	$3.20/KW-Month
Study Length	First Cost Basis	20 Years
Inflation Rate	None	3.00 Percent
NPV Discount Factor	None	9.00 Percent

Study Results

Liberty NPV analysis of Merrimack HP/IP Turbine Replacement
(Nominal Dollars and 2008 Dollars X 10^6 as Noted)

Year	Energy Savings Nominal $	NPV of Energy Savings 2008 $	Cumulative NPV of Energy Savings 2008 $	Maint. Savings Nominal $	NPV of Maintenance Savings 2008 $	Capacity Savings Nominal $	NPV of Capacity Savings 2008 $	Cumulative NPV of Capacity Savings 2008 $
2008	1.62	1.62		1.85	1.85	0.23	0.23	
2009	1.67	1.53				0.24	0.22	
2010	1.72	1.45				0.24	0.20	
2011	1.77	1.37				0.25	0.19	
2012	1.82	1.29	**7.26**			0.26	0.18	**1.02**
2013	1.88	1.22	8.48	1.68	1.09	0.27	0.18	1.20
2014	1.93	1.15	9.63			0.27	0.16	1.36
2015	1.99	1.09	10.72			0.28	0.15	1.51
2016	2.05	1.03	11.75			0.29	0.15	1.66
2017	2.11	0.97	**12.72**			0.30	0.14	**1.80**

2018	2.18	0.92				0.31	0.13	
2019	2.24	0.87				0.32	0.12	
2020	2.31	0.82				0.33	0.12	
2021	2.38	0.78				0.34	0.11	
2022	2.45	0.73	**16.84**			0.35	0.10	**2.38**
2023	2.52	0.69				0.36	0.10	
2024	2.60	0.65				0.37	0.09	
2025	2.68	0.62				0.38	0.09	
2026	2.76	0.59				0.39	0.08	
2027	2.84	0.55	**19.94**			0.40	0.08	**2.82**
Totals		**19.94**			**2.94**		**2.82**	

The analysis above is a NPV analysis of savings. The NPV of savings at any point in time must be compared to the NPV of the investment including carrying charges. The total cost of the project as assumed by Liberty would be $19.20 million ($12 times 1.6). For example, the economic of the project at 20 years would show $25.7 million in NPV savings versus a NPV cost of $19.2 million.

The analysis shows that the 10-year NPV of the project is $17.46 million ($12.72 + $2.94 + $1.80) and that the 15-year NPV of the project is $22.16 million ($16.84 + $2.94 + $2.38) including the savings of the first 5-year maintenance cycle. These values indicate a project payback late in the 12th year.

If one were to further assume that the first 5-year maintenance savings did not occur, the 10-year NPV of the project is $16.37 million ($12.72 + $1.85 + $1.80) and that the 15-year NPV of the project is $21.07 million ($16.84 + $1.85 + $2.38). These values indicate a project payback late in the 13th year.

Liberty concluded that the HP/IP turbine replacement project exhibits very strong economic benefits even if very conservative layered assumptions are used and proceeding with the project was in customers' best interests.

Newington Outages For 2008

Newington-1

The major projects for Newington in 2008 were the removal and inspection of the station's 6 largest motors and two of its medium sized motors and the installation of an upgrade to the turbine control system during the annual outage. For 2008, Newington's availability was above 95 percent. For 2008, Newington's capacity factor was approximately 3 percent. For the years of 2003 through 2005, the unit's capacity factor had hovered from just below 40 percent to above 50 percent. In 2006 and 2007, the unit's capacity factor hovered in the 8 percent range.

The following outages took place at Newington during 2008:

A
1/21 – 0.3 days
While starting the unit, a steam leak developed in the superheater drain line, a 4 inch line. The leak was large enough to warrant repairs so the unit was taken off line. Temporary repairs were made and the unit was returned to service. Permanent repairs were made during the major overhaul described in Outrage B below.

The leak was attributed to flow accelerated corrosion. Flow accelerated corrosion only occurs in carbon/steel pipe at 250 psi to 400 psi with multi phase flow conditions (steam and wet steam) present. Newington was in the process of evaluating its small diameter piping (4 inch) for this condition, but had not yet evaluated this section of pipe. Large diameter piping was evaluated years ago. PSNH also indicated that this issue has already been addressed at Merrimack and Schiller.

B
3/1 – 12.1 days
This was a planned outage to perform a major over haul of the unit and was scheduled for 14 days with the ISO and was completed in just over 12 days. During this outage, both forced draft fans, both induced draft fans, and both circulating pump motors were sent out for a complete inspection. 36 welds of dissimilar material were made in the secondary superheater outlet header. ABB informed PSNH in 2007 that it would no longer support the turbine control system at Newington which was installed in 1992. ABB was offering an upgrade to its existing control systems that would extend their lives by at least 10 years. The outage proceeded without incident.

C
3/14 – 26.2 days
When returning from the annual outage in Outage B above, the unit was operating at a higher MW level than it should have been at. The problem centered on the new speed control that had been installed during the annual outage and the initial settings applied.

The upgraded turbine control system required adjustments to be made exactly at 3600 rpm. Tuning of the speed control was performed and the unit ramped to full load but was cycled off line in the evening due to economics. This outage was taken the next day to make those turbine control system adjustments, was expected, and time had been included in the outage schedule to do so.

The unit was operating at 3600 rpm and de-energized when the closed cooling water plunger seat cracked in the solenoid valve that prevented cooling water from flowing to the two exciter coolers. As a result, the air temperature of the exciter began to rise. An alarm came into the unit operator when the exciter temperature reached 110 degrees F. This alarm is a warning alarm, is called a high cool air alarm, and when reached, procedures require that the operator investigate its cause. A duplicate alarm came in approximately 2 ½ minutes later. No investigation to the cause of the alarms was made. Subsequent to the first alarms and 24 minutes later, a second alarm came into the control room. This alarm occurs when the exciter temperature reaches 170 degrees F, is called a high hot air temperature alarm, and when reached, the operator by procedure is required to shut the unit down. A duplicate alarm came in approximately 9 minutes later. The operator acknowledged all 4 alarms as a group to clear the alarm screen. The operator failed to investigate the alarms and convinced himself that these alarms were not consistent to a de-energized unit. The operator therefore did not initiate a unit shut down.

The operator stated that his experience during de-energized exciter and full speed conditions (Which the unit was under during this outage) during start up lasted for approximately 5 minutes and that he believed that the unit could operate indefinitely in this mode without harm. Due to these operator actions, the exciter was damaged.

Rather than wait 18 to 22 weeks for a new exciter, PSNH decided to participate in the Siemens spare rotor program The Siemens spare rotor was not 100 percent refurbished and the rotor coupling required modification. This rework extended the outage time.

Upon investigation of the incident and to address contributing factors, PSNH has re-emphasized the requirement to follow established procedures and monitor alarms, is continuing training start up exercises every two weeks at Newington (program was initiated just prior to this incident), initiated a comprehensive review of alarm management practices, and disciplined the operator on duty at the time. The specific incident at Newington and these lessons learned programs such as alarm management are also being emphasized at Merrimack and Schiller stations.

D
4/10 – 0.7 days
When returning to service from the installation of the Siemens spare rotor, balancing was required when the unit was phased. This outage was taken to accomplish that balancing. The rotor was balanced in the shop, but shop balancing does not match field conditions. The rotor was balanced and the unit returned to service.

E

7/21 – 0.1 days

The unit was getting ready to start when the low pressure oil trip valve operated and would not open. This problem also occurred in 2007 and no cause was found at that time. In 2007, PSNH installed indicator lights to help troubleshoot the problem if it occurred in the future. Upon investigation, PSNH found that the low pressure oil relay had picked up; however the contacts did not make contact because the plunger had hung up. The relay was replaced and the unit returned to service. Note: The hung up plunger finding is consistent with the investigation conducted in 2007.

F

7/22 – 0.1 days

This outage consisted of a late phasing of the unit. During start up, the B induced draft fan tripped due to a faulty speed switch. PSNH found that the switch setting had moved. PSNH attempted to use the A induced draft fan for start up but the unit also tripped due to a furnace pressure excursion. Motor starting requirements require that a 90 minute waiting period take place between the first and second starts so that motor thermal capabilities are not exceeded. The unit started successfully on the second attempt. PSNH performed troubleshooting of the fan system, exercised the fan system components, but no problems were found.

G

7/24 – 0.7 days

The unit was off line but in reserve status. Water was observed by plant personnel under the boiler. A small leak was found in the economizer outlet in a rear wall tube. Repairs were made and the unit returned to service. The unit was not called for by the ISO during repairs.

H

12/9 – 0.1 days

The problems with the induced draft fan B occurred again on start up after not occurring for months. Induced draft A was used to start the boiler, but the boiler tripped off due to high furnace pressure. PSNH waited 90 minutes to restart the A induced draft fan (cooling requirement), however the unit again tripped on high furnace pressure when an attempt to start was made. PSNH performed extensive mechanical troubleshooting including logic anomalies between the A and the B induced draft fan systems as the feed forward system uses signals and not pressures for activation and the damper/vane drive systems. No binding or rubbing problems were found. PSNH did find some air leaks in several duct expansion joints and scheduled their repair or replacement during the 2009 spring overhaul (Four on the A side and 3 on the B side).

With regard top the B induced draft fan system, investigation found that the relay associated with the motor bearing lube oil pressure (Trips the motor on loss of oil pressure) was faulty. The relay was replaced and similar relays in other systems were tested in the 2009 spring overhaul.

PSNH notes that in 3/09; most of the expansion joints of the induced draft fan system and the feed forward system were replaced. The problem has not reoccurred since that time.

Evaluation for Newington Except Outages C and D

Liberty reviewed these outages and found them either to be reasonable and not unexpected for this unit and it's vintage or necessary for proper operation of the unit. Liberty concluded that PSNH conducted proper management oversight.

Evaluation for Outages C and D

Evaluation of Outage C
Liberty recommends a disallowance for the replacement power costs associated with this outage as the PSNH operator should have followed established procedures rather than to rationalize alternative actions. Temperature, flow, and pressure alarms are some of the most important alarms to occur in a generating station. In addition and simplistically, temperature alarms originate from temperature probes which report temperatures independent of the operational status of the unit. Liberty does not recommend disallowance of net capital costs or net O&M costs associated with this outage due to the complexities of valuing plant in service beyond its book service life and material facts of the instant case. PSNH corrective actions are appropriate and should also be implemented at Merrimack and Schiller stations.

Although Liberty recommends disallowance for replacement power costs for this outage, Liberty commends the operator involved and PSNH for developing a culture at the generating stations in which the operators and other personnel feel comfortable in stepping forward and taking responsibility for their actions. Such a culture can do nothing but improve plant performance. Liberty recommends that the Commission provide an after the fact opportunity for review of PSNH's efforts to mitigate costs to customers in this outage.

Evaluation of Outage D
Liberty recommends a disallowance for the replacement power costs of this outage as the outage would not have been required but for the improper actions described in Outage C above. Liberty recommends that the Commission provide an after the fact opportunity for review of PSNH's efforts to mitigate costs to customers in this outage.

Schiller Unit Outages For 2008

Schiller-4

The following outages occurred at Schiller-4 during 2008.

A
3/25 – 15.6 days
This planned annual maintenance outage had an ISO outage window of 17 days. The major work performed during thus outage was boiler and furnace refractory, non destructive examinations of boiler tubes etc., and the rewind of the induced draft fan. The boiler inspection indicated that the boiler condition was good and no changes in inspection frequencies were recommended. Examination of the pulverizers revealed that wet coal caused some contamination of the bushings and bearings. Liberty raised questions about the availability of soot blower parts. PSNH stated that they too had concerns and met with the vendor prior to the Schiller 6 annual outage (Scheduled later in the year) to be assured of spare parts for that outage and to develop a spare parts list for the soot blowers. PSNH also sated that the valve repair vendor quality control record keeping was being reinforced with the vendor due to inaccuracies noted during this outage. Work was completed within the outage window and the unit returned to service.

The vendor for the precipitators had 22 electrical/control and mechanical recommendations for both Unit-4 and Unit-6 precipitators. This is a considerable number of recommendations, some of which PSNH was planning to address in future outages. After discussion with the vendor, PSNH and the vendor developed a list of projects which should be done, projects which can be deferred or canceled, and a schedule for completion. PSNH has completed many of the recommendations and scheduled some for action during the 2010 maintenance outages which will be a longer outage than normal. Also see Outage 6-D below.

B (Outage Report OR-2008-09)
5/18 – 4.7 days
The unit was taken off line due to a small refractory failure that allowed the gas path to erode a generating tube causing a leak. While the unit was out of service, a total of 6 to 8 small leaks were identified and repaired and the unit returned to service.

C
10/5 – 1.7 days
The unit was taken off line due to a generating tube leak. The leak was repaired and the unit returned to service.

Schiller-5

The following outages occurred at Schiller-5 during 2008.

A (Outage Report OR-2008-01)
1/3– 6.8 days
The unit was taken off line due to loss of control of the temperature of the bed material during an event involving an air heater with broken tubes. PSNH tried to start the auxiliary gas burner but it failed to start and the unit eventually had to be taken off line. Investigation found that the linkage rod to the air damper shaft was not attached. PSNH believes that the attachment mechanism provided by Alstom had workmanship issues and pursued this matter with Alstom. It was decided to replace the entire damper and linkage assembly to eliminate the issue.

PSNH has also changed the Alstom operating procedures regarding the use of the auxiliary gas burner after this event. After dropping load on the unit as the first defense in temperature control, PSNH will now start the gas burner in preparation of further adjustment requirements rather than waiting for them to occur. PSNH believes that this action will provide more timely control of bed material temperature resulting in greater operator ability to keep the unit on line and prevent damage to the bed material.

B
1/11 – 2.4 days
When returning to service from Outage A above, the unit had to be taken off line due to an economizer tube leak at the inlet header. Investigation revealed that it was stress related crack and that it did not show up during the previous spring's non destructive examination. Repairs were made and the unit returned to service.

C (Outage Report OR-2008-05)
2/22 - 14.9 days
PSNH had been planning both an April (Mud season) and October planned maintenance outage for the unit. Low bed material temperature required that the unit be removed from service to prevent bed crusting. The bed was groomed and while returning to service, the forced draft fan experienced a fault which required that it be sent out for repair. With the length of the outage known, PSNH then decided to bring the April planned outage forward to take advantage of the unit down time for this event.

During this outage, PSNH also made permanent repairs to the linkage to the air damper described in Outage A above.

The forced draft fan motor returned to Schiller was rewound with Class H insulation, a higher class insulation than supplied at purchase (Class F). The higher insulation level is required during soft start conditions (Limits voltage drop and current inrush) as required by specification. PSNH uses a soft start for this motor, but a soft start generates more total heat to the motor due to a longer starting duration. Alstom supplied a motor that had 10 percent less copper than required for soft start conditions. PSNH has ordered a new motor that will have the proper capabilities for soft start conditions, will use the rewound motor as a spare, and is pursuing this matter with Alstom. PSNH discovered that the induced draft fan motor has the same soft start issue, but that the soft start capability had been out of service during 2007 and will remain so for future start ups. PSNH is formalizing warranty related claims for both the forced draft and induced draft fan motors.

D
6/2 – 0.1 days
The unit was taken out of service due to a hot inboard bearing on the forced draft fan. Investigation found that the bearing oil filter was plugged. Also, the bearing reached 95 degrees C when the bearing temperature should have alarmed at 90 degrees C. PSNH found that Alstom had set the alarm at 100 degrees C. The alarm point was reset to its proper value and PSNH checked most of the alarm set points at other locations and found no major problems.

E
6/13 – 0.1 days
The unit tripped due to vibration of the forced draft fan. Investigation did not reveal the cause of the trip, but vibration of the inlet ductwork was suspected. The inlet ductwork was insufficiently designed and was to be replaced in its entirety in the October planned outage. The ductwork was replaced by Alstom at their expense and the vibration problem has not reoccurred.

F
10/6 – 0.2 days
The unit tripped due to a trip of the induced draft fan. Indication pointed towards a trip due to high amperage, but investigation revealed that it was a circuit board issue that triggered the alarm. The circuit board was replaced and the unit returned to service.

G
10/17 – 9.7 days
This planned maintenance outage was scheduled with an ISO window of 10 days and was taken to replace what PSNH considered a deficient Alstom design (Alstom disagrees) of the vortex finder, one of which had fallen into the cyclone cone. PSNH had redesigned the equipment by beefing up the Alstom design. Subsequently in 2009, the other 5 vortex finders were replaced with redesigned units. During this outage, the inlet ductwork to the forced draft fan was also upgraded as described in Outage E above. PSNH also repaired 800 air heater tubes with sleeves because of corrosion problems. These sleeves were repaired during the October 2007 outage with 12 inch sleeves which were thought to have resolved the problem, but did not. 48 inch sleeves were used for reinforcement in this outage.

One half of the air heater will be retubed in 2009. PSNH is claiming that the air heater issue is a design defect and is pursuing the matter with Alstom via a warranty claim.

H (Outage Report OR 2008-17)
12/7 – 4.7 days

The unit was operating at reduced loads due to air heater leak problems leading to problems controlling the bed material temperature. The air leaks caused increased forced draft fan loading causing high current readings, increased NOX emissions, and high cyclone temperatures requiring the unit to be taken off line. Seven air heater tubes were plugged and the unit was turned over to operations. While returning to service, the forced draft fan motor drive end bearing overheated due to insufficient oil. The bearing slinger ring was repaired and the unit returned to service.

Schiller-6

The following outages took place at Schiller-6 during 2008:

A
2/14 – 0.1 days
The unit was experiencing wet coal conditions. One pulverizer was lost and while putting in oil guns to support boiler temperature because the pulverizer temperature was below 135 degrees F, the other pulverizer tripped. The oil gun procedure takes approximately one half hour to implement. To shorten the time for intervention, oil would have to be heated and circulated continuously, a process that is expensive and normally not required. A pulverizer mill should be operated at a temperature of 150 degrees F; however temperatures of 135 degrees F and lower can be tolerated while mitigation takes place to prevent loss of boiler fires. Operators are not required to insert oil guns at a temperature of 135 degrees F. As a result of this incident, PSNH reviewed its procedures during low coal pulverizer temperatures and reaffirmed that a dynamic operator response, rather than a prescribed operator response is correct.

B
2/15 – 2.6 days
The unit was taken off line with a controlled shutdown due to a generating tube leak. A total of 4 leaks were found consisting of 2 generating tubes, a waterwall tube, and a tube roll were found. Repairs were made and the unit returned to service.

C
3/24 – 0.8 days
The unit was taken off line due to a chemical injection line leak that was caused by steam blowout from the deaerator due to steam wear. A section of the pipe was replaced and the unit returned to service. Other pipes have been inspected since this incident.

D
4/11 – 14.5 days
This annual planned maintenance overhaul was scheduled with the ISO for 2 weeks (17 days). During this outage major boiler tube reinforcement was performed. The outage

was moved up to the old Unit–5 maintenance window in April to take advantage of personnel on site performing the Unit–4 outage. The outage went as planned.

PSNH instituted a partial soot blower exchange program during this outage as a result of the parts problems that occurred in Outage – SCH-4-A above. Also see Outage 4-A above for status of precipitator repair recommendations.

E
6/18 – 1.6 days
The unit was taken off line due to a generating tube leak. Three leaks were found and repaired and the unit returned to service.

F
7/1 – 2.3 days
The unit was taken off line due to a primary superheater tube leak. The leak was repaired and during the hydro test for the boiler, 24 small leaks were found at the rolls of the tubes at the bottom of the mud drum. Those leaks were welded and the unit returned to service.

G
10/4 – 2.7 days
The unit was taken off line in a controlled fashion due to a primary superheater tube leak. The failed tube and tubes in the area were repaired and the unit returned to service.

H
11/24 – 1.1 days
The unit was taken off line due to a leak at the deaerator flange at the point of connection of the pipe from the tank due to steam wear. The pipe was repaired and the unit returned to service.

Evaluation

Liberty reviewed the outages at Schiller and found them either to be reasonable and not unexpected for these units and their vintage or found them necessary for proper operation of the units. Liberty concluded that PSNH conducted proper management oversight.

Recommendation Regarding Unit 5

Many outages have centered on issues regarding Alstom designs or Alstom workmanship issues. Liberty has reported on the action that PSNH is taking such as making a formal claim etc., however, little is known about the final resolution and the net impact (Replacement power costs versus settlement) it is having on customers. Liberty recommends that PSNH recover replacement power costs for the outages related to warrantee and performance issues in this proceeding. Liberty also recommends that PSNH prepare a report of all such Alstom warranty and performance issues that describe the issue involved, PSNH efforts for resolution with Alstom, and the final resolution. Liberty further recommends that the report be filed by February 1, 2010 and updated in future SCRC reconciliation filings until all issues are resolved. Liberty further recommends that the Commission provide an after the fact opportunity for review of PSNH's efforts to mitigate costs to customers in these outages.

Hydroelectric Unit Outages For 2008

The following describes the outages at PSNH's hydroelectric (hydro) units during 2008. The outage durations listed have been stated as the actual duration of the total outage regardless whether there was water to run the unit. Liberty indicates water availability by a "Y" or "N" next to the outage designation.

Amoskeag Station

Major planned projects at this station included installation of inflatable flashboards to satisfy minimum bypass flow requirements and resurfacing a portion of the dam. Due to high river flows throughout the year and the requirement to keep the pond level below the crest of the dam for the inflatable flashboard project, no annual inspections were made at Amoskeag in 2008. The units were closely monitored for potential problems.

Amoskeag - 1

A
4/11 – 0.02 days – Y
This outage occurred during 2007 and not 2008. It was incorrectly reported. (Also see Outage 2-A and Outage 3-A below)

B
4/15 – 0.25 days – Y
The potential transformer between transformer TB-26 and the TB-26 breaker failed at Eddy substation. The J-114 115 kV breaker was being replaced at the time of the potential transformer failure and the Eddy substation was out of normal configuration with the 358 and 359 34.5 kV lines open at the Rimmon end. Amoskeag is fed directly off of the Eddy 34.5 kV bus and when clearing the potential transformer fault, the Amoskeag generation became momentarily isolated from the system causing the unit to trip.

PSNH reported that the J-114 breaker was being replaced as part of a Northeast Utilities planned breaker replacement project to address its aging circuit breaker population. Replacement dates were based on repair history, availability of spare parts, maintenance costs, and environmental risk.

The master HFA relay coil at Amoskeag also overheated and needed replacement possibly due to sticking contacts on a differential lockout device. All differential lockouts on all units were cleaned, lubed and tested. The units were returned to service. (Also see Outage 2-B and Outage 3-B below)

C
12/5 – 0.03 days – Y
This was a scheduled shutdown of the unit to perform the annual black start and other related emergency tests. The testing could not be done during low flow periods due to inflatable

flashboard work on the dam crest, the requirement to keep pond level below the crest of the dam, and the high water flows experienced during the flashboard work period. After successful completion of the tests, the unit was returned to service. (Also see Outage 2-D and Outage 3-D below)

Amoskeag – 2

A
4/11 – 0.2 days – Y
See dialogue in Outage 1-A above.

B
4/15 – 0.0 days – Y
This outage happened at the same time as Outage 1-B above which explains the outage in detail.

C
6/8 – 0.06 days – N
The unit tripped off line due to a high thrust bearing temperature caused by both high ambient temperatures inside and outside of the building (95 degrees F). Ventilation filters were removed to allow more circulation of air, the bearing was checked, and the unit returned to service. PSNH noted that the fans were replaced with higher volume fans in 2009.

D
12/5 – 0.03 days – Y
This outage happened at the same time as Outage 1-C above which explains the outage in detail.

Amoskeag – 3

A
4/11 – 0.2 – Y
See dialogue in Outage 1-A above.

B
4/15 – 0.04 days – Y
This outage happened at the same time as Outage 1-B above which explains the outage in detail.

C
5/28 – 0.2 days – N
The unit tripped due to activation of the pond control system. The wastegate at Hooksett hydro (7 miles upstream) was closed and caused a sag in the river activating the pond control system. Water flows were such that only this unit was on line at the time, the unit was at minimum load, and would have had to come off line at any time soon anyway.

D
12/5 – 0.03 days – Y
This outage happened at the same time as Outage 1-C above which explains the outage in detail.

Ayer's Island

Major projects at Ayer's Island for 2008 included installation of new trash racks, finalization of the new Osprey camera system which can be accessed by the public (At PSNH.com) and paving of the new parking area.

Ayer's Island – 1

A
3/6 – 0.08 days – N
The unit tripped after phasing on reverse power (initial load not matching minimum excitation settings) when it failed to pick up load. PSNH adjusted the governor control unit and the unit returned to service. (Also see related Outage 1-G below)

B
7/14 – 4.13 days – N
This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. In addition, generation maintenance inspected, cleaned and adjusted the governor.

C
7/21 – 0.07 days – Y
The unit tripped on overspeed. The operator found nothing wrong, reset the overspeed relay, and returned the unit to service. The operator also called for the overspeed controls to be checked. (See Outage 1-D below)

D
7/21 – 0.06 days – Y
The unit again tripped on overspeed while the overspeed controls were being checked. Investigation found that the mechanical overspeed switch failed. The failed switch was removed and the electronic overspeed controls were tested prior to returning the unit to service. A spare mechanical overspeed switch was ordered that day for installation during the 2009 annual inspection. The failed switch was sent out for repair and will serve as a spare when returned.

E
9/15 – 0.25 days – Y
This was a scheduled outage for the entire station to ensure diver safety during installation of the new trash racks. (Also see Outage 2-D and Outage 3-B below)

F
9/17 – 0.18 days – N
This was a scheduled outage to ensure diver safety during installation of the new trash racks.

G
10/8 – 0.30 days – Y
The unit tripped when the unit would not pick up load after phasing. Investigation found that the SCADA panel relay had failed. The relay was replaced, an operational check made, and the unit returned to service. A spare relay was also ordered. PSNH believes that this relay was the root cause of Outage A above because if the relay temporarily stuck, it would have driven the governor motor to minimum settings causing the unit to trip.

Ayer's Island – 2

A
2/11 – 2.45 – N
This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

B
7/19 – 0.02 days – N
The unit tripped on overspeed due to a line fault on the 3114 34.5 kV line and the opening and closing of that circuit at the Pemigewasset substation. The Ayers Island generation is fed out of the Pemigewasset substation by the radial 3149 34.5 kV line. This is an overtrip condition. The PSNH standard practice is to not specify reclosing times less than 5 seconds on a circuit such as the 3114 34.4 kV line and the 3149 34.5 kV line to Ayer's Island.

This is an area of apparent mis-coordination between PSNH lower voltage generating units and the distribution system. PSNH states that future review is required. Please see recommendation at end of this report.

C
7/28 – 0.01 – Y
The unit tripped due to a high lower guide bearing temperature. The temperature in the building was at 90 degrees F with all fans in operation. An operator happened to be present and checked the guide bearing temperature. It was found to be 58 degrees C compared to the trip setting of 60 degrees C. The bearing and the temperature device were checked and the unit was returned to service. PSNH will install a new wall fan later in 2008 and will have a fan operational when generating. The wheel pit fan will be thermostatically controlled to operate when air temperature is 70 degrees F.

D
9/15 – 0.25 days – Y
This outage happened at the same time as Outage 1-E above which explains the outage in detail.

E
9/18 – 0.40 days – N
This was a scheduled unit shutdown to ensure diver safety during the installation of the new trash rack.

F
9/19 – 0.04 days – N
This was a scheduled unit shutdown to ensure diver safety during the installation of the new trash rack.

G
9/20 – 0.26 days – N
This was a scheduled unit shutdown to ensure diver safety during the installation of the new trash rack.

H
9/22 – 0.37 days – N
This was a scheduled unit shutdown to ensure diver safety during the installation of the new trash rack.

I
9/23 – 0.32 days – N
This was a scheduled unit shutdown to ensure diver safety during the installation of the new trash rack.

J
9/24 – 0.31 days – N
This was a scheduled unit shutdown to ensure diver safety during the installation of the new trash rack.

K
9/25 – 0.29 days – N
This was a scheduled unit shutdown to ensure diver safety during the installation of the new trash rack.

L
10/3 – 0.01 days – Y
The unit was taken off line when an operator saw a shiny spot on the exciter commutator. Inspection revealed that one of the brush holders had moved. The brush holder was adjusted, the other brush holders were checked, and the unit was returned to service.

Ayer's Island – 3

A
9/13 – 0.34 days – N
This was a scheduled unit shutdown to ensure diver safety during the installation of the new trash rack.

B
9/15 – 0.05 days – Y
This outage happened at the same time as Outage 1-E above which explains the outage in detail.

C
10/20 – 4.33 days – N
This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

Canaan

Major activities at this station in 2008 included relicensing studies, since Canaan's FERC license is currently undergoing FERC review. Major construction projects may be required to satisfy future license requirements dictated by the Vermont Water Quality Certificate. PSNH is currently appealing the conditions imposed. In 2008, extensive retaining wall repairs were made. The penstock is scheduled to be replaced in 2009.

Canaan – 1

A
3/6 – 0.07 days – Y
A fault occurred on the VELCO system which is tapped off of the PSNH 355X10 34.5 kV line. The phase conductor came down and Canaan tripped at the same time. No breaker operations occurred on the PSNH system. VELCO opened the J-510 switch to isolate the area to facilitate VELCO repairs and the unit returned to service.

This is an area of apparent mis-coordination coordination between PSNH lower voltage generating units and the distribution system. PSNH states that future review is required. Please see recommendation at end of this report.

B
3/6 – 0.01 days – Y
PSNH closed the J-510 switch to restore service to the VELCO load tapped off of the PSNH 355X10 34.5 kV line at VELCO's request. When closed, the unit tripped. There were no breaker operations on the PSNH system. The switch was opened and the unit returned to service.

This is an area of apparent mis-coordination. PSNH states that future review is required. Please see recommendation at end of this report.

C
4/23 – 0.09 days – Y
Lightning was being experienced in the area. The 0355 34.5 kV breaker at Lost Nation tripped and reclosed. The unit was temporarily isolated from the system and tripped on overspeed.

PSNH also reported one operation of the 357 breaker. The 357 breaker trips on undervoltage. The unit returned to service without incident when released by the dispatcher.

This is an area of apparent mis-coordination coordination between PSNH lower voltage generating units and the distribution system. PSNH states that future review is required. Please see recommendation at end of this report.

D
5/15 – 0.06 days – Y
The former Groveton Village substation was in the process of being decommissioned when a piece of falling steel caused contact in the substation. The piece of steel fell on to a neutral wire below causing the poles to move and caused the phase conductors of the mobile transformer (Feeding the 13H1 circuit) to slap together. The 0355 34.5 kV breaker at Lost Nation properly tripped and reclosed because the point of contact was beyond the high side fuse protection of the mobile transformer. The unit was temporarily isolated from the system and tripped on overspeed. PSNH also reported one operation of the 357 breaker. While cutting steel, the torch man did not cut a piece of steel all the way through as he should have causing the steel to pivot on the remaining steel hinge as it fell. When the hinge broke, the steel fell in an unexpected direction towards the neutral conductor. The torch man had a ground spotter for safety and was counseled after the incident. Liberty views this incident as accidental. The unit returned to service when released by the dispatcher.

E
5/23 – 0.09 days – Y
A tree fell on the 355X line causing the 0355 34.5 kV breaker at Lost Nation to trip and reclose. The unit was temporarily isolated from the system and tripped on overspeed. The 355 right of way underwent trimming in 2007, however the subject tree was located outside of the right of way. PSNH states that danger trees were removed and side trimming was done on the right of way in 2007 when those vegetation programs commenced. PSNH further states that many of their old easements including those at issue here do not contain language that specifically provides rights to take down trees outside of the easement. The unit returned to service when released by the dispatcher.

F
5/31 – 0.14 days – Y

The center phase wire came off its insulator during a storm due to a broken tie wire causing the 0355 34.5 kV breaker at Lost Nation to trip and reclose twice. The unit was temporarily isolated from the system and tripped on overspeed. Voltage sensing switch 355-J9 also operated and isolated the Canaan unit at the same time. PSNH states that all 34.5 kV lines in rights of way were thermographically inspected aerially in 2007 – 2008. The 355 line was inspected on May 17, 2008 and a broken tie wire was not identified at that time. PSNH also states that declining REP funding has caused constraints and other types of patrols were not performed. Repairs were made and the unit returned to service.

G

6/10 – 0.10 days – Y

The northern part of the PSNH system was experiencing a severe lighting storm. 115 kV breakers D-1420 and S-1360 tripped and locked out at Whitefield isolating the Lost Nation and Berlin substations except by the 376 34.5 kV line between Whitefield and Lost Nation. A tree that had fallen from the edge of the right of way was found on the D-142 115 kV line between Whitefield and Lost Nation. The TB-33 transformer opened at Lost Nation causing loss of power to the 355 34.5 kV line and the trip of the Canaan unit. The fault condition needed to be isolated prior to re-energizing the 115 kV system. During this series of events, the Canaan unit, Smith hydro, and Gorham G-2 tripped. The dispatcher removed the remaining 3 units at Gorham from service. The D-142 right of way was mowed in 2003 and was scheduled for mowing in 2009. PSNH states that they have a 10-year side trim maintenance program and that the edge of the rights of way is patrolled every two years to identify and correct hazardous conditions. The unit returned to service when released by the dispatcher.

H

6/10 – 0.09 days – Y

Lightning was being experienced in the area. The 0355 34.5 kV breaker at Lost Nation tripped and reclosed. The unit was temporarily isolated from the system and tripped on overspeed. PSNH also reported one operation of the 357 breaker on undervoltage. The unit returned to service without incident.

I

8/13 – 0.01 days – Y

A loon flew into the 355X10 34.5 kV distribution line in Stewartstown. A 40T fuse on one phase operated and cleared the fault. There were no breaker operations on the PSNH distribution system and the Canaan unit tripped at the same time. Repairs were made, the other fuses were visually inspected, and the unit returned to service. PSNH checked fuse coordination and it was found to be proper.

This is an area of apparent mis-coordination coordination between PSNH lower voltage generating units and the distribution system. PSNH states that future review is required. Please see recommendation at end of this report.

J

8/17 – 4.42 days – Y

This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

K

8/26 – 0.05 days – Y

The Hydro Quebec feed to the VELCO system was lost. VELCO requested that the J-510 switch be closed to restore service to VELCO customers off of the PSNH 355X10 34.5 kV distribution line. The Canaan unit tripped on overspeed when the switch was closed and no breaker operations occurred on the PSNH system. The unit returned to service when released by the system dispatcher.

This is an area of apparent mis-coordination coordination between PSNH lower voltage generating units and the distribution system. PSNH states that future review is required. Please see recommendation at end of this report.

L
9/13 – 0.17 days – Y
A tree fell on the 355X line causing the 0355 34.5 kV breaker at Lost Nation to trip and reclosed twice. The unit was temporarily isolated from the system and tripped on overspeed. The 355 right of way underwent trimming in 2007, however the subject tree was located outside of the right of way. The unit returned to service when released by the dispatcher.

This is an area of apparent mis-coordination coordination between PSNH lower voltage generating units and the distribution system. PSNH states that future review is required. Please see recommendation at end of this report.

M
10/9 – 0.08 days – Y
A black bear climbed the 355 34.5 kV line and came into contact with the neutral and primary wires causing the 0355 34.5 kV breaker at Lost Nation to trip and reclose. The unit was temporarily isolated from the system and tripped on overspeed. The unit returned to service when released by the dispatcher.

N
11/24 – 1.05 days – Y
This was a scheduled outage for the unit to have consultants inspect and have access to the inside and outside of the penstock in preparation of the upcoming penstock replacement project in 2009.

O
12/25 – 0.13 days – Y
Windy conditions caused multiple contacts on the 355X10 34.5 kV distribution line. There were no breaker operations on the PSNH distribution system, but it is believed that the contacts recorded caused the unit to trip on overspeed. The unit returned to service when released by the system dispatcher.

This is an area of apparent mis-coordination coordination between PSNH lower voltage generating units and the distribution system. PSNH states that future review is required. Please see recommendation at end of this report.

Eastman Falls

The major projects at this station for 2008 included resurfacing of the dam, a rewind of the G-1 generator, and improvements to the G-2 ventilation system.

Eastman Falls-1

A
2/7 – 0.07 days – Y
The unit tripped off line immediately after start up. It appeared to the operator that the unit did not pick up load fast enough causing the unit to trip. The relay was reset and the unit was returned to service. The unit was monitored and no anomalies were noted.

B
3/26 – 0.10 days – Y
The 337 34.5 kV line sustained a fault due to a failed polymer suspension insulator causing the 337 34.5 kV breaker to trip and reclose. The insulator failure subsequently flashed over to the J-125 115 kV line that is on the same pole and on the same side of the pole. This fault caused the J-1250 breaker at Webster and the TB-125 low side transformer breaker also to trip and reclose. Eastman Falls is tapped off of the 337 34.5 kV line and when this line tripped, the unit was temporarily isolated from the system and tripped on overspeed. The unit returned to service when released by the dispatcher. PSNH estimates that the distance between the two conductors is 66 inches which meets NESC requirements. (Also see Outage 2-B below)

C
6/26 – 0.08 days – N
The unit tripped on overspeed due to a fault in the speed module relay. The speed module relay was replaced and the unit was returned to service. The relay output was monitored to see if the event happened again. During the annual inspection (Outage D below), the electronic overspeed was recalibrated.

D
9/2 – 146.29 days – Y
This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. During this inspection, a new Kingsbury thrust bearing was installed (emergent work), the generator was rewound, and the generator rotor and exciter were inspected and cleaned resulting in the requirement to rewind the exciter. Upon startup, the thrust bearing was found not to be in the correct position. Modifications were made to the thrust bearing at the contractor's expense. The unit was returned to service without incident.

Eastman Falls – 2

A
3/13 – 0.17 days – Y
This scheduled outage was taken to change the oil filter on the hydraulic system as scheduled. In many cases, if the unit is down for another reason the filter can be changed without the need for a specific outage. The filter was changed and the unit returned to service.

B
3/26 – 0.05 days – Y
This outage happened at the same time as Outage 1-B above which explains the outage in detail.

C
5/28 – 0.08 days – N
The unit failed to start due to an incomplete starting sequence and not achieving minimum power output requirements. The programmable logic controller was adjusted to have the unit pick up 0.9 MW on startup (From 0.6 MW) and the unit was returned to service.

D
6/11 – 0.35 days – N
While the unit was off line, a high sump level alarm was triggered. A water/oil mix was drained from the hydraulic tank, new oil was added, and the unit was returned to service. The problem for the water intrusion, leaking seals on the stub shaft, was corrected during the annual inspection in Outage H below.

E
6/23 – 0.06 days – N
The unit tripped when a high sump level alarm was triggered. A water/oil mix was drained from the hydraulic tank, new oil was added, and the unit was returned to service. The problem for the water intrusion, leaking seals on the stub shaft, was corrected during the annual inspection in Outage H below.

F
6/23 – 0.03 days – N
While the unit was off line, a creep alarm was initiated. Two sensors ensure that the lube pumps are operating whenever the generator/turbine shaft is turning (Potential leak in intake gates). A mismatch in this requirement is called creep and will alarm and shut the unit down. Inspection found no anomalies and the unit was returned to service. (Also see related Outage G below)

G
6/27 – 0.01 days – N
While the unit was off line, another creep alarm was initiated. Again inspection and review of the programmable logic controller found nothing wrong. The alarm was concluded to be extraneous and a 30 second time delay was inserted into the creep alarm logic when the unit is off line. When the unit is on line, there is zero time delay to initiate a trip for creep conditions. The unit returned to service without incident.

H
8/4 – 24.25 days – Y
This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. The nose cone area was inspected, stub shaft seals were replaced, and weld repairs were made to the runner blades.

Garvins Falls

Major work at the station in 2008 included the replacement of the station step up transformer, work on the Shoreline Management plan, and the Recreation Management Plan.

Liberty notes that the annual inspections at Garvins could not be done concurrently with the replacement of the step transformer as no station services were available while the new step up transformer was being installed.

Garvins Falls-1

A
6/9 – 15.11 days – N
This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. Cracked blades were also repaired.

B
8/25 – 26.38 days – N
This scheduled outage was taken to replace TB-36, the station step up transformer with a new more efficient unit. In addition the start up transformer for G-1 and G-2 had to be removed from service to facilitate demolition. The 115 kV bus had to be de-energized requiring that all four units to be taken out of service. This outage is reflected in Outages 2-A, 3-B, and 4-C below, however, outages for G-3 and G-4 were for only 5 days.

C
9/27 – 0.05 days – Y
The unit would not automatically phase onto the system when requested by the dispatcher. A local operator phased the unit on with local control and returned the unit to supervisory control. The dispatcher was able to control the unit. Investigation found nothing wrong, and the auto/local/supervisory switch was cleaned. The problem has not reoccurred.

Garvins Falls – 2

A
8/25 – 26.38 days – N
This outage is identical to Outage 1-B above which contains the outage details.

B
11/3 – 37.38 days – Y
This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. In addition, major work was performed on the head gates.

Garvins Falls – 3

A
6/23 – 2.32 days – N
This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

B
8/25 – 5.35 days – Y
This outage is identical to Outage 1-B above which contains the outage details. This outage is for a shorter duration.

Garvins Falls – 4

A
6/16 – 4.19 days – N
This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

B
6/22 – 0.06 days – N
The pond control system took the unit off line. Investigation found that the pond control system was working within its parameters, but the generation level at that time could not be supported by the river flow. This incident occurred during the time period when the pond control system was being fine tuned. Adjustments were made to the pond control system and the unit returned to service.

C
8/25 – 5.36 days – Y
This outage is identical to Outage 1-B above which contains the outage details. This outage is for a shorter duration.

D
12/28 – 2.18 days - N
A low oil alarm for the lower guide bearing was received by the dispatcher. When a station operator arrived, he found that the oil pump was not returning oil from the bearing sump to the bearing reservoir fast enough. The unit was immediately taken off line. Investigation found that the oil return line was being restricted by a kink in the line. The line was replaced and the unit returned to service.

Gorham

The minimum flow gate and fifty hinged flashboards were replaced in 2008. An underground auxiliary power cable from the upper gatehouse to the station was also installed.

Gorham – 1

A
1/24 – 0.00 days – Y
Infrared inspection revealed that disconnect DX5308 in the generation area of the substation was hot. The entire station was taken off line and DX5308 was exercised. PSNH thermographically inspects all generation disconnects annually. The units returned to service. Also see Outage 2-A, Outage 3-A, and Outage 4-A below.

B
3/11 – 0.02 days – Y
The entire station tripped off line when a raccoon made contact with the low side bushing (22 kV) on TB-47 at Eastside substation. The protection operated correctly, however the 0351 34.5 kV breaker at Gorham also tripped at the same time causing the Gorham units to trip for this event. Animal guards were installed at this substation by PSNH, but TB-47 is a customer owned transformer and was not protected. The units were returned to service when released by the dispatcher. Also please see Outage 2-B, Outage 3-C, and 4-B below and Outrage Smith 1-A below.

This is an area of apparent mis-coordination coordination between PSNH lower voltage generating units and the distribution system. PSNH states that future review is required. Please see recommendation at end of this report.

C
6/10 – 0.04 days – Y
Thunderstorms were being experienced in the northern portion of the PSNH system causing 115 kV outages and other units to trip and voltage instability. The dispatcher removed Gorham station from the system as an instability precaution. The units were returned to service when the storms passed and voltage swings stabilized. Please also see Outage 2-C, Outage 3-I, and Outage 4-H below and Outage Smith 1-E below.

D
7/28 – 0.04 days – Y
The unit tripped off line due to a failed MW transducer. The transducer was replaced and the unit returned to service.

E
10/6 – 3.25 days – N
This scheduled outage was taken to perform the annual inspection. Both units 1 and 2 are done at the same time as they have a common intake structure. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. In addition, a problem was discovered with the draft tubes; however divers were not available at this time. Inspection of the draft tubes therefore required a special outage. Please see Outage 1-H and Outage 2-F below.

F
10/15 – 0.12 days – Y
This was a scheduled outage for the entire station so that the neutral protection scheme on the station grounding bank could be reconfigured to address distribution wire routing concerns. The work was performed and the units returned to service. Also see Outage 2-E, Outage 3-L, and Outage 4-I below.

G
10/25 – 0.03 days – Y
A fault occurred on the 351 34.5 kV line between Whitefield and Berlin. The 351 breaker at Whitefield and the 352 breaker at Gorham (On the 352 line between Gorham and Berlin) tripped. PSNH has the choice of two mis-coordination scenarios here. The current scheme prevent prevents the 351 breaker from operating for faults on the 352 line is chosen over its opposite scenario which trips Gorham station.

This is an area of apparent mis-coordination coordination between PSNH lower voltage generating units and the distribution system. PSNH states that future review is required. Please see recommendation at end of this report.

H
10/29 – 0.16 days – Y
This scheduled outage was taken to inspect the draft tubes as a result of the annual inspection. Both G-1 and G-2 have a common intake. Divers found that the G-1 draft tubes needed to be replaced. PSNH has scheduled this work for 2009. Also see Outage 2-F below.

Gorham – 2

A
1/24 – 0.00 - Y
This outage is identical to Outage 1-A above which contains the outage details.

B
3/11 – 0.02 days – Y
This outage is identical to Outage 1-B above which contains the outage details.

C
6/10 – 0.05 days – Y
This outage is identical to Outage 1-C above which contains the outage details.

D
10/6 – 3.25 days – N
This outage is identical to Outage 1-E above which contains the outage details.

E
10/15 – 0.12 days – N
This outage is identical to Outage 1-F above which contains the outage details.

F
10/29 – 0.16 days – Y
This outage is identical to Outage 1-H above which contains the outage details.

Gorham – 3

A
1/24 – 0.0 days – Y
This outage is identical to Outage 1-A above which contains the outage details.

B
2/7 - 0.05 days – Y
The unit tripped when the power supply for the electronic tachometer/overspeed device tripped. The power supply was reset and the tachometer/overspeed and the unit was returned to service. A new power supply was ordered and installed on 4/28. Also see Outage E below.

C
3/11 – 0.02 days – Y
This outage is identical to Outage 1-B above which contains the outage details.

D
3/17 – 0.01 days – Y
During a routine check of the exciter brushes, it was observed that one was worn more than the others, so the unit was taken off line. All six brushes were replaced as a precautionary measure and the unit was returned to service.

E
4/28 – 0.08 days – Y
The unit tripped when the power supply for the electronic tachometer/overspeed device tripped. The power supply was replaced with the one ordered in February and the unit was returned to service.

F
6/3 – 0.01 days – Y
The unit was taken out of service to replace the exciter brush holder springs. After the brush replacement in Outage D above, PSNH monitored the brushes and determined that the brushes were wearing down too fast. The brush holder springs were replaced and the unit returned to service.

G
6/7 – 0.04 days – Y
The unit tripped off line due to high thrust bearing temperature. The trip point for thrust bearing temperature is 70 degrees C. The temperature in the station was above 90 degrees F. In addition, the water level was at dam crest level to facilitate flash board replacement leaving the oil cooler in the wheel pit partially exposed and thus receiving less cooling from the water flow. Fans were added on the top of the unit to draw air through the unit and windows were

closed so that cooler air would be drawn from the floor of the station. The unit was returned to service.

H
6/8 – 0.53 days – Y
The units again tripped off line due to high thrust bearing temperature after the remedies in Outage G above were applied. Discussion with maintenance determined that the set point for the thrust bearing trip temperature could be raised to 75 degrees C. The change was made and the unit returned to service.

I
6/10 – 0.04 days – Y
This outage is identical to Outage 1-C above which contains the outage details.

J
7/17 – 2.34 days – N
This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

K
9/1 – 0.03 days – Y
The unit tripped due to loss of field. The operator found that the 34.5 kV voltage was swinging between positive and negative. The operator waited until the bus voltages and reactive output were normal and phased the unit on line. The unit was monitored for an hour and all seemed normal.

L
10/15 – 0.12 days – Y
This outage is identical to Outage 1-F above which contains the outage details.

M
10/25 – 0.02 days – Y
This outage is identical to Outage 1-G above which contains the outage details.

N
11/26 – 0.00 days - Y
The unit tripped due to a malfunction of the overspeed relay card. (Note – This was the new power supply installed on 4/28) The card was removed and reinserted and the unit returned to service. PSNH is finding that the electronic overspeed devices on older units are having problems due to stray EMF in common cable trays. The electronic overspeed devices at Gorham will be changed to mechanically driven devices in 2009.

Gorham – 4

A
1/24 – 0.00 days – Y
This outage is identical to Outage 1-A above which contains the outage details.

B
3/11 – 0.03 – Y
This outage is identical to Outage 1-B above which contains the outage details.

C
4/15 – 0.03 days – Y
The unit tripped due to low oil pressure. Investigation found that the actuator (Builds oil pressure) was working properly, oil pressure was normal, and no indications of other problems were found. The unit was returned to service. Also see Outage D, Outage E, Outage F, and Outage G below.

D
4/16 – 0.06 days Y
The unit again tripped on low oil pressure. The oil pressure in the tank was again found to be normal. The wiring on all switches, the actuator motor, and the actuator motor were checked. The oil filter was also changed even though it appeared normal. In addition, all switches and the motor were checked. Nothing abnormal was found and the unit was returned to service pending further troubleshooting later in the day. This outage is related to Outage C above and Outage E, Outage F, and Outage G below.

E
4/16 – 0.05 days – Y
The unit was taken off line to perform more troubleshooting. Testing of the actuator pump motor contacts indicated that one contact may be bad. All three contacts were replaced. After testing, readings were normal. The unit was returned to service and new overload contacts were ordered as the operator also suspected that the problem may be related to the overload devices. This outage is related to Outage C and Outage D above and Outage F and Outage G below.

F
4/17 – 0.05 days – Y
During operational testing, the operator felt that the actuator pump took too long to pick up its suction. The actuator pump was replaced and the unit returned to service. Plans were made to rebuild the actuator hydraulic piston during the annual inspection outage. (Outage K below) Also see Outage C, Outage D, Outage E above and Outage G below.

G
4/18 – 0.05 days – Y
The unit again tripped off line due to low oil pressure. In rush current readings were also taken on the actuator pump motor. Since the actuator contacts were replaced in Outage E above, a bad overload device on the actuator pump motor was suspected. After the motor starter overloads had cooled, the unit was returned to service. The new overload devices ordered on 4/16 were installed later that day with the unit on line. Also see Outage C, Outage D, Outage E, and Outage F above.

H
6/10 – 0.04 days – Y
This outage is identical to Outage 1-C above which contains the outage details.

I
10/15 – 0.12 days – Y
This outage is identical to Outage 1-F above which contains the outage details.

J
10/25 – 0.02 days – Y
This outage is identical to Outage 1-G above which contains the outage details.

K
11/10 – 16.20 days – Y
This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. In addition, the lower guide bearing was replaced and the actuator piston was rebuilt.

Hooksett

The major projects completed at Hooksett in 2008 included the replacement of the trash racks and updating the building ventilation system.

Hooksett – 1

A
3/4 - 0.02 days – Y
When cleaning the trash racks, the trash rack rake boom got stuck in the down position due to an internal hydraulic failure. The unit was taken out of service so the boom could be safely removed. Repairs were made and the unit returned to service.

B
4/7 – 0.05 days – Y
The unit was taken off line because the governor was not responding to raise and lower pulses. Investigation revealed that the synchronizing motor clutch needed adjustment due to wear. The adjustment was made and the unit returned to service.

C
7/21 – 28.11 days – Y
This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. The intake racks were also replaced during this outage. The replacement racks were built to very old station prints; however alignment problems were encountered during installation requiring dimension modifications.

D
10/15 – 0.17 days – Y
This outage was scheduled to have divers install shims between the new intake racks and their support structures. Shims were required because of contour differences between the racks and the support structures. This work was not able to be completed during the annual inspection

(Outage C above) because the material could not be procured during the window of that outage. Repairs were made and the unit returned to service.

Jackman

The major project for this station in 2008 was an upgrade of the station ventilation system.

Jackman-1

A
2/1 – 0.08 days – N
The unit tripped on overspeed due to the tripping and reclosing of oil circuit recloser OCR-73 on the 3173 line (Two times). The operation of the oil circuit recloser was initiated by a limb falling on the line during a snowstorm. The circuit was last trimmed in 2007 and the origin of the limb was determined to be from outside of the trim zone. Investigation indicated that the Jackman undervoltage relay should have ridden through the event and it did. The unit was returned to service when released by the dispatcher.

This is an area of apparent mis-coordination coordination between PSNH lower voltage generating units and the distribution system. PSNH states that future review is required. Please see recommendation at end of this report.

B
2/13 – 0.06 days – N
A tree limb fell onto the 3140 34.5 kV circuit out of Jackman during a snow storm. The 3140 34.5 kV breaker at Jackman tripped and reclosed twice. The unit tripped on overspeed at the same time. The unit returned to service when released by the dispatcher.

This is an area of apparent mis-coordination coordination between PSNH lower voltage generating units and the distribution system. PSNH states that future review is required. Please see recommendation at end of this report.

C
3/28 – 0.11 days – Y
This outage was scheduled so that trip circuits could be installed in preparation for the installation of the 115 kV mobile substation. The mobile substation is required to provide continuity of service while a major transmission project (Installation of 2-13.3 MVAR 115 kV capacitor banks) was performed in the high yard of the station. The accommodations were made and the unit returned to service.

D
4/18 – 0.05 days – Y
The unit tripped due to a high thrust bearing temperature. The unit was placed in local control and returned to service with PSNH monitoring the thrust bearing temperature. The temperature of the bearing was 89 degrees F and the operator attempted to further cool the bearing by opening windows and doors without obtaining relief. Fans were added to the wheel pit areas

and the exciter area and the unit operated throughout the weekend. Note – the new ventilation system had not yet been installed. Also note that a new and higher temperature Kingsbury bearing was installed in Outage E below.

E
5/5 – 30.24 days – N
During the upgrade of the transmission side of the substation, a contactor's excavator boom contacted the generator output cables that connect to the generator step up transformer. The contact resulted in the failure of the generator step up transformer. No injuries were reported. Inspection revealed that no other equipment was damaged during the incident. The outage was required to allow time to bring in a mobile transformer replacement. The mobile transformer would allow operation of the unit up to 2.2 MWs.

The annual inspection was conducted during this outage and the thrust bearing was replaced with a new Kingsbury type of bearing.

The contractor had swapped out the smaller machine being used in the grading of the substation. PSNH specifically instructed the contractor not to use the larger machine inside the substation, but when the PSNH inspector left, the larger machine was brought into the substation to perform the remaining work tasks. The incident occurred even though the contractor had a spotter who was determined to be "inattentive" at the time of the incident.

The contractor has accepted total responsibility for the incident and PSNH is pursuing financial compensation including replacement power costs.

F
8/8 – 0.34 days – Y
The mobile substation acting in place of the generator step transformer tripped due to a vehicle accident and subsequent fault that that occurred on 3173 34.5 kV circuit out of Jackman. PSNH electricians inspected the mobile sub, reset all drops, and restored service to the mobile sub. The unit was restarted without incident.

This is an area of apparent mis-coordination coordination between PSNH lower voltage generating units and the distribution system. PSNH states that future review is required. Please see recommendation at end of this report.

G
9/9 – 0.03 days – Y
The unit tripped off line on overspeed. There were no known power outages in the area at the time. Station controls checks revealed no problems. The unit was returned to service. A power quality meter was installed for 30 days, but no anomalies were found.

This is an area of apparent mis-coordination coordination between PSNH lower voltage generating units and the distribution system. PSNH states that future review is required. Please see recommendation at end of this report.

H
11/6 – 0.25 days – N
The unit tripped off line while a transmission contractor was performing relay and control work in the substation. Investigation found that circulating current of approximately 1 amp was flowing in the CT residual circuit (CT circuit shorted and bus de-energized condition) and was sufficient enough to initiate the trip. A potential of 0.19 volts existed between the point of grounding of the relay ground and the relay cabinet. The unit was returned to service. Further work included the installation of new 4/0 ground conductors being installed between the old control house and the new 115 kV control house to reduce the potential difference.

I
12/2 – 0.01 days – N
The unit tripped when transmission contractors working in the substation caused the auxiliary breaker on the mobile 34.5 kV substation to operate and in turn causing the trip of the unit. During the removal of the front access panel in the distribution control room, a breaker for the mobile substation popped out of place. This panel is similar to the breaker panel a residential homeowner has in his basement. A white caution tag had been installed on the panel indicating that operation of this breaker would trip the unit. When the face panel was removed, the breaker was activated and the unit tripped. The breaker was reset and the unit returned to service.

Smith

Major projects at this station in 2008 included the installation of 11 cooling fans on the generator step up transformer and the rebuilding of the control and communications line between the hydro station and the East side substation.

Smith-1

A
3/11 – 0.01 days – Y
This outage is identical to Outage Gorham 1-B above which contains the outage details.

B
3/31 – 0.05 days – Y
The unit tripped off line due to loss of oil pressure to the turbine bearing. Investigation found that the spider coupling on the AC motor/pump had failed. The backup DC pump was found operating but its operation was not sufficient to allow continued operation of the unit. The spider coupling was replaced and the unit was returned to service and PSNH informed the ISO that it would request an outage later in the day for trouble shooting. Also see Outage 1-C below.

C
3/31 – 0.06 days – Y
This outage was taken to determine why the backup DC lube pump did not allow continued operation of the unit in Outage 1-B above. The AC and backup DC oil pumps feed a common header and the pressure is monitored by a common pressure sensing switch. If pressure is not

detected, a slow shutdown of the unit is initiated. PSNH staged a shutdown of the unit by a loss of AC pump oil supply. The DC backup pump started immediately and oil pressures were measured as normal, but after 15 seconds the unit tripped on low oil pressure. Investigation found that adequate oil was flowing when the DC backup pump was running, but the flow was not enough to keep the pressure switch in the open position. An adjustment was made to the oil pressure switch, testing was performed to ensure proper operation, and the unit returned to service. Also see Outage 1-B above. Note – PSNH installed a new DC lube pump in Outage 1-D below which further increased oil pressure when on the DC backup lube pump.

D
4/12 - 0.46 days – Y
This outage was scheduled to allow the control and communication cable between the station and Eastside substation to be moved to new poles. PSNH could not wait until the annual inspection as the wetland permit required the work to be done while ice was still present. The unit was required to be out of service to maintain system integrity and the safety of the unit. Work was performed on a Saturday to minimize replacement power costs. The DC lube pump (see Outage 1-C above) was also replaced during this outage. The cable work was performed and the unit returned to service.

E
6/10 – 0.01 days – Y
This outage is identical to Outage Gorham 1-C above which contains the outage details. The unit tripped while it was being taken off line.

F
9/6 – 5.25 days – Y
This scheduled outage was taken to perform the annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. In addition, the oil header piping and check valves for the AC and DC turbine bearing system were replaced.

G
10/14 – 0.06 days – Y
The unit was taken off line due to a leak in the turbine bearing oil line emanating from the new header system installed on 9/6. The turbine bearing oil line consisted of many couplings and one union. Over time, vibration caused the fittings to leak. The brass oil line and fittings were replaced with a high pressure hydraulic flex hose and stainless fittings, the repairs were made, and the unit returned to service. PSNH states that this line was in an area that was not visible when the header was replaced in Outage 1-F above.

Evaluation for Hydro Units Except Outage Garvin's Falls 4-D, Jackman 1-E, Jackman 1-H, and Jackman 1-I

Liberty reviewed these outages and found them either to be reasonable and not unexpected for these units and their vintage or necessary for proper operation of the units. Liberty concluded that PSNH conducted proper management oversight.

Evaluation for Garvins Falls Outage 4-D

A kink in the oil return line has to occur from human handling during normal cleaning operations or other work related to the return lube oil system. When dismantling and reassembling the oil return line, it must be moved to allow line up of the connections. Liberty believes that an operator did not exercise due care during one of these operations. Further, the operator should have known the oil line was kinked; known that oil flow could be restricted to the reservoir, and should have either replaced the line immediately or as soon as possible. Liberty recommends disallowance of replacement power costs for this outage.

Evaluation for Jackman Outage 1-E

For the contractor to directly ignore PSNH instructions indicates a significant weakness in the understanding between PSNH and contractors working in PSNH substations and the authority of the contractor to change PSNH instructions. Liberty also notes that PSNH supervision was heavily concentrated at the Mammoth Road TB-73 transformer upgrade project at the time of this incident. Liberty recommends disallowance of replacement power costs for this outage.

Evaluation for Jackman Outage 1-H

When doing incremental projects in old substations, grounding configuration, adequacy, and location may not be fully known. A ground potential check is done to ensure proper grounding between the existing and new work. A ground potential check was not part of this project and Liberty recommends disallowance of replacement power costs for this outage.

Evaluation of Outage Jackman 1-I

There has been a rash of contactor related outages at hydro stations and many of them appear due to speed of work and therefore lack of due care. In this case, the breaker could not have tripped unless it was bumped during a hasty removal of the panel cover or the white tag became entangled in the panel cover upon removal. In either case, due care was not exercised. There appears to be a weakness in the PSNH/contractor relationship on the expectation of due care to be exercised when in PSNH substations. Liberty recommends disallowance of replacement power costs for this outage.

Recommendation Regarding Outages Due to Trees Outside of 34.5 kV Rights of Way

Outages Canaan 1-E and Canaan 1-L were caused by trees which PSNH stated were outside of the right of way. PSNH further states that many of its older 34.5 kV lines in rights of way (1,600 miles plus) do not have language in the easements that allow PSNH to address "danger trees" outside of the right of way. PSNH therefore does not address the outside of right of way danger tree issue. Liberty recommends that PSNH address danger trees that are outside of the 34.5 kV rights of ways, include identification of such trees in NESC required patrols, and identify where PSNH has and does not have the rights to do so. Liberty further recommends that this issue be specifically addressed in the 2009 Reliability Enhancement Program contained in PSNH's current rate case.

Recommendation Regarding Lack of NESC Patrols.

In its explanation regarding Outage Canaan 1-F, PSNH stated that that patrols were limited to aerially thermographic inspection of 34.5 kV lines in rights of way due to constraints of declining Reliability Enhancement Program funding. Liberty understands that PSNH had agreed to perform inspections of all distribution facilities on a 4 year schedule as part of its 2006 REP plan. Liberty recommends that this issue be specifically addressed in the 2009 Reliability Enhancement Program contained in PSNH's current rate case.

Recommendation Regarding Apparent Mis-coordination Between PSNH Lower Voltage Generation and the Distribution System

Many outages above involve apparent mis-coordination between PSNH lower voltage generating units and the distribution system. PSNH has begun an analysis regarding settings etc. and suspects that some trip settings may be set too tight. PSNH also states that many of its small generating stations do not have regimented relay testing requirements by NPCC or NERC as they are not considered bulk power facilities. PSNH does perform relay testing on all units. PSNH further states that relay settings have not changed at its small generating stations since the early 1980s. While new generation coming onto the PSNH system has undergone an interconnection analysis that reviews coordination, no such analysis has been done for PSNH's own units. Liberty recommends that PSNH perform interconnection analyses for all combustion turbines and hydro units connected to the lower voltage PSNH system. Merrimack combustion turbines and Smith hydro are connected to the 115 kV system and such mis-coordination does not exist. Liberty further recommends that PSNH establish an appropriate relay testing program for all combustion turbines and hydro units. Liberty suggests that PSNH complete this work prior to the next SCRC filing and file a report of its actions concurrent with that filing.

Combustion Turbine Outages For 2008

The following outages took place at PSNH's combustion turbine units during 2008:

Lost Nation CT-1

Major work that was completed at Lost Nation during 2008 included the installation of high capacity emergency vents on the two fuel storage tanks to comply with the latest fire standards and the installation of oil leak detectors to comply with environmental regulations.

Lost Nation – 1

A
4/14 – 4.33 days
This scheduled outage was taken to perform the annual inspection. Included in the work performed were a visual inspection, general cleaning, and annual equipment tests and servicing the diesel starter engine. Testing and inspections revealed no abnormalities.

White Lake CT-1

Major work that was completed at White Lake during 2008 included the installation of high capacity emergency vents on the four fuel storage tanks to comply with the latest fire standards and the installation of oil leak detectors to comply with environmental regulations.

White Lake – 1

A
3/11 – 0.31 days
The E-SCC dispatcher received an alarm that the unit failed to start while the unit was not in operation or under request to do so. The unit had a new controller installed in October 2007 along with other control changes. The Ethernet module in the new Programmable Logic Controller (PLC) was found to be defective and bypassed so the unit could be returned to service on a remote basis. The module was replaced on 3/14.

B
4/28 – 4.00 days
This scheduled outage was taken to perform the annual inspection. Included in the work performed were a visual inspection, general cleaning, and annual equipment tests. Testing and inspections revealed no abnormalities.

C

6/2 – 0.32 days

The E-SCC dispatcher received an alarm that the unit failed to start while the unit was not in operation or under request to do so. The module position switch (detects loose logic cards) in the new PLC was found to be defective and replaced. The unit was returned to service.

D

6/13 – 0.09 days

The E-SCC dispatcher received an alarm that the unit failed to start while the unit was not in operation or under request to do so. The system computer was found in the off position and would not restart. The operator unplugged and plugged the computer back in resulting in a successful reboot. The unit was returned to service. Subsequent investigation warranted the installation of an Uninterrupted Power Supply which was installed on 7/29. The UPS installation seems to have corrected the problem.

E

7/18 – 0.13 days

The E-SCC dispatcher received an alarm that the unit failed to start while the unit was not in operation or under request to do so. Thunderstorms in the area caused a vibration alarm that initiated the alarm. Alarms were cleared and the unit was returned to service. The vibration monitor was scheduled to be calibrated on 7/30.

F

7/24 – 0.07 days

The E-SCC dispatcher received an alarm that the unit failed to start while the unit was not in operation or under request to do so. Thunderstorms in the area caused a vibration alarm that initiated the alarm. Alarms were cleared and the unit was returned to service. On 7/30, the vibration monitor was calibrated and reconfigured so that it would be in the off position when the unit was not in operation and turned on when the start command is given.

G

9/26 – 0.15 days

The E-SCC dispatcher received an alarm that the unit failed to start while the unit was not in operation or under request to do so. The operator found the generator breaker tripped and a generator high temperature alarm. The operator removed and reinstalled the generator trip circuit card in the annunciator panel (not part of the new controller) which successfully reset the alarm. The unit was returned to service. Subsequent testing of the generator trip relay, remote temperature devices, and wiring found no abnormalities.

Schiller CT-1

A
1/17 – 0.3 days
The unit failed to start when called on by the ISO. Low air pressure maxed out the pressure speed timer. The air compressor was undergoing repairs in Germany and air pressure was taken from Schiller Station to start the unit. To increase efficiencies and reduce losses, the air pressure at Schiller was reduced to 250# from 500# which is insufficient to start the unit. The time/speed setting was increased to allow more time to bring the unit up to required speed before alarming. PSNH has set up an evaluation team to evaluate this unit including maintenance practices and problems occurring at this unit. PSNH notes that the recommendations were implemented in 2009.

B
3/3 – 1.4 days
The unit was scheduled for its annual inspection with ISO-NE starting 3/8 (effectively 3/10 for normal work days). The unit was mistakenly taken out of service a week early while Schiller Station was in an outage for Unit #5. While reassembling the unit, the replacement of a damaged igniter extended the outage. The igniter was damaged during reassembly of the unit when a shroud for the hot side of the burner cans was slid back over the igniter section of the combustion turbine to allow accesses to the burners cans. The exciters are somewhat delicate and located in close proximity to the shrouds. This type of damage has not been common over the almost 40 year life of the unit. Liberty views this incident as accidental. Once reassembled, the unit was returned to service.

To prevent reoccurrence of taking the unit out on the wrong date, PSNH reviewed week beginning and week ending calendars as used by the ISO with maintenance personnel.

C
3/10 – 4.5 days
This scheduled outage was taken to perform the annual inspection. Included in the work performed were a visual inspection, general cleaning, and annual equipment tests. Testing and inspections revealed no abnormalities.

D
6/5 – 0.1 days
While in standby mode, an alarm for high generator stator temperature was received. Investigation found the trip relay in the trip position. The relay was cleaned and tested and the unit was returned to service. A new relay was ordered to replace the exiting relay at an appropriate time in the future.

E
6/20 – 0.0 days
While in standby mode, an alarm for high generator stator temperature was received. Investigation found the trip relay in the trip position. This is an identical outage cause as discussed in Outage D above. The new relay ordered as a result of Outage D above was

received on 6/17 and there was insufficient time since receiving the relay for it to be installed prior to this outage. The new relay was installed at this time.

F
9/28 – 0.1 days
While in standby mode and connected to the 34.5 kV system (The Schiller CT has the capability to feed into the 34.5 kV system or to Schiller Station), a lightning arrestor just outside the coal pile on the 367 34.5 kV line failed. The failed lightning arrestor was isolated, the unit was switched to its alternate feed, and the unit was returned to service.

G
10/20 – 0.1 days
The unit was called to operate by the ISO and went to full load. After approximately 5 minutes, a vibration alarm for probe #3 shut the unit down. Investigation found that one of the vibration probes was dirty. The probe was cleaned and the unit was returned to service. PSNH notes that all probes were inspected and cleaned in the 2009 annual inspection.

H
10/28 – 0.0 days
This was a short scheduled outage to replace a thermocouple monitoring temperature of the turbine. Two turbine temperature alarms were received the previous day and identified the need for replacement.

Merrimack CT-1

Major work completed at the Merrimack combustion turbine included the removal and replacement of the free (rotating blade) turbine on CT-1.

CT-1 and CT-2 are connected to the 115 kV transmission yard via a common step transformer and have common fuel systems. Some of the concurrent outages listed below are a result of those configurations.

A
4/21 – 4.3 days
This scheduled outage was taken to perform the annual inspection. Included in the work performed were a visual inspection, general cleaning, and annual equipment tests. Testing and inspections revealed no abnormalities. During this inspection, the free turbine (rotating blade) was replaced with a loaner so the PSNH turbine could be refurbished. Once refurbished, the PSNH turbine would be reinstalled (See Outage 1-E below)

Although not required to because of configuration, the CT-2 annual outage was performed at the same time. (Also see Outage 2-A below)

B

5/7 – 0.2 days

This outage was taken to replace a "T" in the CT-1 fuel line. The "T" was replaced and the unit was returned to service.

A fuel filter leak on CT-2 was also repaired during this outage. (Also see Outage 2-B below)The fuel system consists of common fuel tanks with a common feed line and a common filter. The fuel system then splits into two lines with a separate filter for each unit.

C

5/10 – 0.2 days

This outage was taken to repair a lube oil pump leak. The leak was repaired and the unit was returned to service.

D

7/21 – 1.0 days

While in operation, a high vibration initiated a unit trip. The turbine vendor did a boroscope examination of the area surrounding the vibration location for damage.
No damage was found. The vibration probe was replaced and the unit started without incident.

E

10/6 – 4.1 days

This scheduled outage was taken to reinstall the PSNH free turbine so that the loaner turbine could be returned. (Also see Outage 1-A above)

F

10/26 – 0.1 days

During the Merrimack-1 overhaul, the CT-1 circuit breaker was replaced. It was required to de-energize the bus to test this breaker. (Also see Outage 2-D below)

Merrimack CT-2

A

1/5 – 1.4 days

This scheduled outage was taken to perform the annual inspection. Included in the work performed were a visual inspection, general cleaning, and annual equipment tests. Testing and inspections revealed no abnormalities. This outage was done in conjunction with Outage 1-A above.

B
5/7 – 0.2 days
This outage was taken to repair a fuel filter leak on CT-2 and was done in conjunction with a fuel line repair to CT-1. The leak was repaired and the unit was returned to service. (Also see Outage 1-B above)

C
10/20 – 1.0 days
The unit was called upon to run by the ISO. CT-2 failed to phase to the system. Bad diodes were found in the dead bus relay board. The relay board was replaced and the unit was returned to service.

D
10/26 – 0.1 days
This outage was required so that the bus could be de-energized for testing of the new generator breaker on CT-1 because of the step transformer configuration. (Also see Outage 1-F above)

Evaluation Except for Outages Schiller CT-1 A and B

Liberty reviewed the outages above and found them either to be reasonable and not unexpected for these units and their vintage, or necessary for proper operation of the unit. Liberty concluded that PSNH conducted proper management oversight.

Schiller CT-1 Outages A and B

Schiller CT-1, Outage 1-A
This outage is for identical reasons as the outage described in the review of the 2007 SCRC (Outage H on 12/13). Liberty recommends that the replacement power relative to this outage be disallowed. The decision to reduce air pressure at Schiller either had no review or a review at such a level that the combustion turbine was not considered. Even a cursory review should have raised the question of adequate air pressure for starting the combustion turbine.

Schiller CT-1, Outage 1-B
The time for the outage and outage extension were 0.65 days and 0.78 days respectively. Liberty recommends that the replacement power relative to the early removal of the unit (0.65 days) be disallowed. Removal of the unit was not adequately communicated especially when the well established intent of outage scheduling at Schiller is to sequence unit outages for work force purposes. Operators should have known outage schedules and unit scheduling requirements.

W. F. Wyman-4 Outages For 2008

W. F. Wyman-4 Station

The W. F. Wyman Station was sold to a competitive power supplier and competes in the New England competitive market to sell its power. Florida Power & Light (FP&L) owns the majority of the unit and is responsible for day-to-day operations. PSNH is a 3 percent minority owner of Unit #4 at the station, and as such, is aware of how the plant conducts business. However, PSNH has little influence over day-to-day operations of the plant provided those operations are within wide operating bounds. This unit is an extremely high cost oil unit that has tight environmental operating restrictions placed on it. The unit operates at an annual capacity factor of approximately 5 percent. Liberty makes this distinction because it believes that the measurement of prudence is different than the measurement used for PSNH's wholly-owned and controlled units providing energy at cost to PSNH customers because of the extent of outside ownership.

The major projects performed at Wyman-4 this year were the replacement of the deteriorating generator step up transformer and the rewind of the generator stator described in Outage I below.

W. F. Wyman-4

A
1/22 – 0.1 days
In 6/07, a new control system was installed. When putting the unit on line, the operator must match certain pressures in the boiler. The boiler was in variable pressure mode during this startup when the boiler tripped due to SUSD (Start up – shut down) procedure irregularities. Investigation found that the proper steps for start up in the variable pressure mode were not in the operator's procedures nor had they ever been. The step missed by the operator was to push the run button which is required of all equipment start functions. It is not known how or why the operator skipped this step. FP&L added this specific step to the procedures and refreshed all personnel on this matter.

B
2/4 – 0.1 days
The unit tripped due to a master fuel trip on high/low furnace pressure. The forced draft fans and the induced draft fans have variable pitch blades that must be coordinated when firing a set of burners. The induced and forced draft fan coordination needed calibration due to the installation of the new control system in 6/07 and was performed at this time. When the new control system was installed, the fan manufacturer set the induced draft fan blade angle at zero degrees with zero demand. After problematic starts, including this outage, and limited number of starts for troubleshooting, the manufacturer tuned the blade setting to -2 degrees and added a time delay. Such work is part of the tune-up process for the new control system.

C (Outage Report OR-2008-04)
2/11 – 6.0 days
The unit was not dispatched at the time of this outage. A fault occurred in the 6.9 kV bus between the station service starting transformer (T-12) and the switchgear. Investigation found that the heaters in the bus were not functional allowing moisture to build up in the bus sections. Subsequent freezing and thawing cycles led to tracking and ultimate failure. Inspection revealed excessive moisture in the remaining bus sections and a measurement of the heater current draw indicated that only possibly one of twenty heaters was operational.

The bus work was repaired and an emergency generator was used to load the bus to dry the bus insulation until insulation readings were acceptable. Once insulation was acceptable, welders were used to maintain a 200 amp load on the bus until new heaters could be installed. The unit was returned to available status. The replacement heaters were ordered and replacement of the heaters was projected to be done in the spring (See Outage E below).

FP&L checked all similar busses in the plant and found that the current draw of the heaters was satisfactory. FP&L has also installed meters that show heater current draw that operators check when making rounds.

D
5/7 – 0.1 days
A faulty low pressure switch tripped a fuel oil pump causing a master fuel trip of the unit. The switch was repaired and the unit returned to service.

E
5/11 – 6.2 days
This outage was a planned outage to install the bus duct heaters that were ordered as a result of the outage described in Outage C above.

F
6/9 – 0.1 days
The operator missed the high temperature alarm on the inlet gas temperature to the induced draft fan. The cause of the high temperature alarm was that there was too much fuel input to the boiler. Because of the high gas temperature, the induced draft fan tripped and shut the unit down. Investigation found that the high temperature alarm was masked due to a large number of alarms coming in during startup including those generated by required tuning for the new control system. In the later part of 2008, FP&L installed an alarm management system to help manage alarms through prioritization, levels, etc.

G
6/20 – 1.5 days
This was a planned maintenance outage. Water had been observed coming from the boiler. A tube leak was found and repaired and the unit was returned to service.

H

7/18 – 0.0 days

This outage is similar to the outage described in Outage B above where a unit trip occurred due to a master fuel trip because of high/low furnace pressure. It was thought that the replacement of the faulty low pressure switch in Outage D above rectified the problem. Investigation found nothing out of order.

I

9/13 – 58.7 days

This major planned overhaul was taken to rewind the generator stator and to perform other scheduled maintenance activities. The station experienced water leaks in 2004 and 2005. Insulation testing of the generator stator in 2006 indicated that the insulation was starting to fail. A rewind of the generator stator was recommended by the original equipment manufacturer and was scheduled to take place during the annual 2008 overhaul.

Dissolved gas analysis of the generator step up transformer indicated that gassing (Indicating deteriorated insulation) was taking place for 4 years. In 2008, it was estimated that the insulation had an 18 month remaining life, so the transformer was scheduled to be replaced during the 2009 annual outage. Because of the need to rewind the generator stator, the step up transformer was replaced during this outage.

J

11/10 – 2.2 days

After the unit returned to service from the major overhaul described in Outage I above, performance testing was required related to the generator and the generator step up transformer. This outage was taken to perform that performance testing.

K

11/12 – 0.4 days

After the unit returned to service from the major overhaul described in Outage I above, performance testing was required related to the generator rotor and the generator step up transformer. This outage was taken to perform that performance testing.

L

11/13 – 2.2 days

After the unit returned to service from the major overhaul described in Outage I above, performance testing was required related to the generator rotor and the generator step up transformer. This outage was taken to perform that performance testing.

M

11/15 – 0.3 days

After the unit returned to service from the major overhaul described in Outage I above, performance testing was required related to the generator rotor and the generator step up transformer. This outage was taken to perform that performance testing.

Evaluation
Liberty reviewed the outages above and found them either to be reasonable and not unexpected for this unit and its vintage, or necessary for proper operation of the unit. Liberty concluded that PSNH conducted proper management oversight.

Recommendation Regarding Outage C
Merrimack and Schiller stations do not have heaters in their isophase bus ducts due to their initial base load design and operation. Newington does have heaters and will be inspecting them prior to the winter freeze and thaw cycles. Liberty recommends that due to shifting market conditions that can change the operation of both Merrimack and Schiller, that PSNH evaluate the need for heaters in their isophase bus ducts.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01
Dated: 06/15/2009
Q-STAFF-010

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, page 1, lines 7-9. Please state how your former responsibilities will be carried out in the future and by whom. As part of your response, please indicate whether your replacement will be in New Hampshire or Connecticut and, if in Connecticut, the reason(s) for moving the position. Related to your new position, please identify the person you replaced.

Response:
A replacement is presently being sought from both inside and outside the company. Present expectations are that my replacement will have my former responsibilities after due allowance for learning the job. In the meantime my former responsibilities are being fulfilled through the coordinated efforts of a number of people. The normal reporting location of my replacement may be Berlin, Connecticut or Manchester, New Hampshire. The location will be driven by the preference of my replacement. All applicants will be made aware that their primary responsibility will be to support PSNH's power supply needs and will be expected to work closely with New Hampshire based employees and New Hampshire regulators.

I replaced Mr. Carl Vogel.

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, page 1, line 17 through page 2, line 4. Please describe the 2008 PSNH strategies to a) procure energy to supplement PSNH resources, b) procure capacity to supplement PSNH resources, and c) acquire FTRs to manage congestion. If those strategies have changed from 2007, please explain the changes and the reasoning for those changes.

Response:
PSNH's supplemental energy purchase strategy is described in Section V .B.6 of the 2007 Least Cost Integrated Resource Plan, filed Sep 28, 2007 in Docket DE 07-108. Details of the supplemental energy procured for 2008 are provided in response to Q-STAFF-016.

During 2008, supplemental capacity was procured via the ISO-NE administered transition period capacity market. Exhibit RCL-5 summarizes the purchase activity.

PSNH procures FTRs to hedge the potential for congestion between significant supply resources (Merrimack, Schiller, Newington, and the delivery location for bilateral purchases, e.g. the Mass. HUB) and the New Hampshire load zone. See response to Q-STAFF-021 for details of the FTRs purchased during 2008.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01
Dated: 06/15/2009
Q-STAFF-012
Page 1 of 1

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, page 3, lines 17-22. Please provide the customer migration assumptions used by PSNH in its capacity and energy purchases and actual capacity and energy requirements for 2008.

Response:

The table below compares the customer migration sales estimate used in the initial 2008 ES rate request to the actual migration sales (MWH).

	2008 Customer Migration	
	Estimated	Actual
JAN	20,528	29,206
FEB	19,701	21,382
MAR	20,500	20,482
APR	20,148	36,865
MAY	21,420	32,618
JUN	21,695	28,661
JUL	23,003	19,929
AUG	22,977	16,931
SEP	21,750	11,420
OCT	22,520	17,564
NOV	20,714	36,066
DEC	19,113	50,155
TOTAL	254,068	321,280

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01
Dated: 06/15/2009
Q-STAFF-013
Page 1 of 1

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, page 3, lines 22-23. Please explain how PSNH supplemental purchase requirements are heavily influenced by the economics of Newington when Newington and Wyman combined supply only 2 percent of on-peak and 1 percent of off-peak PSNH energy requirements.

Response:
The economics (cost) of running Newington and/or Wyman compared to the available market alternatives will drive the level of market activity that PSNH needs to transact for and therefore these units do heavily influence supply alternatives. For example, in 2003 Newington and Wyman combined to serve 27% of PSNH's on-peak energy requirement, while supplemental power served only 12%. In 2008, the Newington and Wyman contribution was 2% of the on-peak energy, while supplemental power served 44%.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01
Dated: 06/15/2009
Q-STAFF-014
Page 1 of 2

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, page 4, lines 3-13. Please provide a schedule, by month, supporting how the 1795 GWH on-peak bilateral purchased energy breaks down into the components listed with average price for each and total.

Response:
See attached.

	2008 On-Peak Bilateral Energy Purchases							
	Monthly Fixed-Price		Unit-Contingent (Bethlehem)		Short-Term Fixed-Price		Total	
	MWh	Avg $/MWh	MWh	Avg $/MWh	MWh	Avg $/MWh	MWh	Avg $/MWh
Jan	88,000	$88.17	5,364	$84.40	35,200	$92.01	128,564	$89.06
Feb	100,800	$88.93	5,126	$84.40	8,000	$83.63	113,926	$88.35
Mar	117,600	$88.37	3,394	$72.50	14,400	$87.17	135,394	$87.85
Apr	228,800	$80.60	8,656	$72.50			237,456	$80.30
May	201,600	$79.39	11,092	$72.50			212,692	$79.03
Jun	151,200	$84.39	11,420	$72.50	28,800	$125.22	191,420	$89.83
Jul	140,800	$90.65	11,645	$80.47	27,200	$134.33	179,645	$96.60
Aug	134,400	$90.65	9,919	$76.54	4,000	$116.00	148,319	$90.39
Sep	134,400	$81.92	11,029	$72.50			145,429	$81.20
Oct	92,000	$83.92	12,414	$71.73			104,414	$82.47
Nov	76,000	$83.92	9,499	$71.67	9,600	$68.50	95,099	$81.14
Dec	88,000	$83.92	10,535	$72.50	4,000	$61.05	102,535	$81.85
Total	1,553,600	$84.81	110,093	$74.68	131,200	$105.10	1,794,893	$85.67

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01
Dated: 06/15/2009
Q-STAFF-015

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, page 4, lines 14-22. Please provide a schedule, by month, supporting how the 831 GWH off-peak bilateral purchased energy breaks down into the components listed with average price for each and total.

Response:
See attached.

	2008 Off-Peak Bilateral Energy Purchases							
	Monthly Fixed-Price		Unit-Contingent (Pinetree)		Short-Term Fixed-Price		Total	
	MWh	Avg $/MWh	MWh	Avg $/MWh	MWh	Avg $/MWh	MWh	Avg $/MWh
Jan	34,000	$73.80	6,002	$62.60	800	$65.00	40,802	$71.98
Feb	30,800	$73.72	5,056	$62.60	9,600	$72.33	45,456	$72.19
Mar	52,350	$75.15	3,731	$54.50	2,000	$64.90	58,081	$73.47
Apr	117,600	$65.96	9,116	$54.50			126,716	$65.14
May	134,000	$64.20	11,654	$51.57			145,654	$63.19
Jun	48,000	$74.29	11,144	$54.50	17,600	$118.41	76,744	$81.53
Jul	48,400	$77.23	11,430	$61.12	24,800	$124.45	84,630	$88.89
Aug	52,400	$77.43	12,984	$66.22			65,384	$75.21
Sep	33,600	$73.86	12,965	$54.50			46,565	$68.47
Oct	31,600	$73.61	12,452	$54.50			44,052	$68.21
Nov	38,450	$74.16	12,547	$55.19			50,997	$69.85
Dec	34,000	$73.80	11,530	$54.50			45,530	$68.92
Total	655,200	$71.13	120,611	$56.92	54,800	$110.34	830,611	$71.67

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, page 4, lines 21-22. Please combine the totals of the above two requests and add the ISO-NE hourly spot purchases to support that combined expenses were $267 million.

Response:
See attached.

On-Peak	2008 On-Peak Bilateral Energy Purchases								ISO-NE Spot Market Purchases		Total Supplemental Purchases		
	Monthly Fixed-Price		Unit-Contingent (Bethlehem)		Short-Term Fixed-Price		Total Bilateral Purchases						
	MWh	Avg $/MWh	MWh	Avg $/MWh	MWh	Avg $/MWh	MWh	Avg $/MWh	MWh	Avg $/MWh	MWh	Cost $000	Avg $/MWh
Jan	88,000	$88.17	5,364	$84.40	35,200	$92.01	128,564	$89.06	20,123	$98.73	148,687	13,437	$90.37
Feb	100,800	$88.93	5,126	$84.40	8,000	$83.63	113,926	$88.35	20,244	$98.12	134,171	12,052	$89.82
Mar	117,600	$88.37	3,394	$72.50	14,400	$87.17	135,394	$87.85	10,967	$112.71	146,361	13,130	$89.71
Apr	228,800	$80.60	8,656	$72.50			237,456	$80.30	1,024	$252.45	238,479	19,327	$81.04
May	201,600	$79.39	11,092	$72.50			212,692	$79.03	1,669	$100.45	214,361	16,977	$79.20
Jun	151,200	$84.39	11,420	$72.50	28,800	$125.22	191,420	$89.83	10,147	$138.62	201,567	18,601	$92.28
Jul	140,800	$90.65	11,645	$80.47	27,200	$134.33	179,645	$96.60	36,271	$144.89	215,916	22,610	$104.71
Aug	134,400	$90.65	9,919	$76.54	4,000	$116.00	148,319	$90.39	16,490	$92.90	164,809	14,939	$90.64
Sep	134,400	$81.92	11,029	$72.50			145,429	$81.20	34,898	$77.63	180,327	14,519	$80.51
Oct	92,000	$83.92	12,414	$71.73			104,414	$82.47	53,569	$69.22	157,982	12,319	$77.98
Nov	76,000	$83.92	9,499	$71.67	9,600	68.50	95,099	$81.14	26,264	$75.50	121,363	9,699	$79.92
Dec	88,000	$83.92	10,535	$72.50	4,000	61.05	102,535	$81.85	19,923	$77.01	122,458	9,927	$81.07
Total	1,553,600	$84.81	110,093	$74.68	131,200	$105.10	1,794,893	$85.67	251,589	$94.45	2,046,482	177,537	$86.75

Off-Peak	2008 Off-Peak Bilateral Energy Purchases								ISO-NE Spot Market Purchases		Total Supplemental Purchases		
	Monthly Fixed-Price		Unit-Contingent (Bethlehem)		Short-Term Fixed-Price		Total Bilateral Purchases						
	MWh	Avg $/MWh	MWh	Avg $/MWh	MWh	Avg $/MWh	MWh	Avg $/MWh	MWh	Avg $/MWh	MWh	Cost $000	Avg $/MWh
Jan	34,000	$73.80	6,002	$62.60	800	65.00	40,802	$71.98	30,653	$74.46	71,454	5,220	$73.05
Feb	30,800	$73.72	5,056	$62.60	9,600	$72.33	45,456	$72.19	30,350	$79.53	75,806	5,695	$75.13
Mar	52,350	$75.15	3,731	$54.50	2,000	64.90	58,081	$73.47	20,744	$78.18	78,824	5,889	$74.71
Apr	117,600	$65.96	9,116	$54.50			126,716	$65.14	23,593	$86.54	150,309	10,296	$68.50
May	134,000	$64.20	11,654	$51.57			145,654	$63.19	7,478	$94.17	153,132	9,908	$64.70
Jun	48,000	$74.29	11,144	$54.50	17,600	$118.41	76,744	$81.53	41,298	$96.51	118,042	10,243	$86.77
Jul	48,400	$77.23	11,430	$61.12	24,800	124.45	84,630	$88.89	67,282	$97.72	151,912	14,097	$92.80
Aug	52,400	$77.43	12,984	$66.22			65,384	$75.21	18,796	$73.65	84,180	6,302	$74.86
Sep	33,600	$73.86	12,965	$54.50			46,565	$68.47	64,962	$66.40	111,527	7,502	$67.26
Oct	31,600	$73.61	12,452	$54.50			44,052	$68.21	34,559	$61.35	78,611	5,125	$65.19
Nov	38,450	$74.16	12,547	$55.19			50,997	$69.85	23,484	$62.85	74,481	5,038	$67.64
Dec	34,000	$73.80	11,530	$54.50			45,530	$68.92	16,523	$81.38	62,054	4,482	$72.24
Total	655,200	$71.13	120,611	$56.92	54,800	$110.34	830,611	$71.67	379,721	$79.70	1,210,332	89,796	$74.19
2008 Total	2,208,800	$80.75	230,704	$65.40	186,000	$106.64	2,625,504	$81.24	631,310	$85.58	3,256,814	267,333	$82.08

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, page 4, lines 27-28. Please provide a schedule, by month, supporting how the 169 GWH of energy that was sold on-peak and the average price received.

Response:
See the attached table, which answers both Q-STAFF-017 and Q-STAFF-018.

2008 On-Peak

	Total ISO-NE Spot Sales MWh	Surplus Sales from Generation MWh	Surplus Sales from Bilateral MWh	Total ISO-NE Spot Sales $000	Avg Sale $/MWh
Jan	9,480	60	9,420	866	91.31
Feb	4,647	34	4,613	287	61.72
Mar	18,819	258	18,560	1,350	71.72
Apr	26,783	7	26,775	2,589	96.66
May	35,981	0	35,980	3,846	106.88
Jun	16,441	0	16,441	1,743	106.04
Jul	9,699	29	9,670	1,064	109.74
Aug	21,161	40	21,122	1,484	70.14
Sep	4,466	3	4,463	285	63.81
Oct	915	0	915	51	56.24
Nov	5,817	0	5,817	313	53.89
Dec	14,985	1,709	13,277	780	52.08
Totals	169,193	2,140	167,053	14,659	86.64

2008 Off-Peak

	Total ISO-NE Spot Sales MWh	Surplus Sales from Generation MWh	Surplus Sales from Bilateral MWh	Total ISO-NE Spot Sales $000	Avg Sale $/MWh
Jan	5,869	727	5,142	485	82.65
Feb	5,362	702	4,660	269	50.16
Mar	17,083	2,809	14,274	1,130	66.13
Apr	4,385	0	4,385	326	74.27
May	42,582	1,221	41,361	3,414	80.16
Jun	6,850	406	6,444	416	60.67
Jul	2,938	17	2,920	210	71.44
Aug	11,837	932	10,905	676	57.15
Sep	2,941	184	2,757	167	56.94
Oct	2,789	106	2,683	130	46.67
Nov	17,455	4,129	13,325	845	48.43
Dec	24,503	7,598	16,905	1,017	41.49
Totals	144,593	18,831	125,762	9,084	62.83

2008 Totals

	Total ISO-NE Spot Sales MWh	Surplus Sales from Generation MWh	Surplus Sales from Bilateral MWh	Total ISO-NE Spot Sales $000	Avg Sale $/MWh
Jan	15,348	787	14,561	1,351	88.00
Feb	10,009	736	9,273	556	55.53
Mar	35,902	3,067	32,834	2,479	69.06
Apr	31,168	7	31,161	2,915	93.51
May	78,563	1,221	77,341	7,259	92.40
Jun	23,291	406	22,885	2,159	92.69
Jul	12,636	46	12,590	1,274	100.84
Aug	32,998	972	32,027	2,161	65.48
Sep	7,407	186	7,221	452	61.08
Oct	3,703	106	3,598	182	49.04
Nov	23,272	4,129	19,142	1,159	49.79
Dec	39,489	9,307	30,181	1,797	45.51
Totals	313,786	20,971	292,815	23,743	75.67

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01
Dated: 06/15/2009
Q-STAFF-018
Page 1 of 1

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, page 4, lines 28-30. Please repeat the above request for the 145 GHW of off-peak energy sales and combine the two to support that combined revenue was $23.7 million.

Response:
See response to Q-STAFF-017.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01
Dated: 06/15/2009
Q-STAFF-019
Page 1 of 1

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, page 5, lines 15-16. Please explain how PSNH's resource mix provides price stability during periods of high and volatile natural gas prices .

Response:
As detailed in the testimony, PSNH's power supply portfolio includes hydro , nuclear, coal, and biomass generation, as well as a unit capable of burning either residual fuel oil or natural gas . A diversified portfolio, such as PSNH's, provides a more stable power supply price than a portfolio that is less balanced, e.g. a portfolio that is entirely based on resources that utilize natural gas . With a diversified portfolio, a change in the price of a single fuel source will have less of an impact on PSNH than if PSNH relied solely on that fuel source .

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01
Dated: 06/15/2009
Q-STAFF-020
Page 1 of 1

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, page 8, lines 6-8. With a declining capacity factor at Newington, why does PSNH procure FTRs for this station?

Response:
On-peak FTRs were purchased for Newington in the months of July and August. The FTRs were purchased to support anticipated operation of Newington in those months.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01
Dated: 06/15/2009
Q-STAFF-021
Page 1 of 3

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, page 8, lines 6-19. Please provide by month and in the form provided in previous dockets, the value and cost of FTRs. As part of your response, please also list the FTR amounts for Merrimack, Schiller and Newington stations.

Response:
The attached tables provide the requested information.

Cost and Value of FTRs

2008	Month	FTR Auction $	FTR Value $	Net FTR $
	Jan	(92,803)	(9,389)	(102,192)
	Feb	(55,695)	20,523	(35,172)
	Mar	(44,076)	6,057	(38,019)
	Apr	3,553	(12,871)	(9,318)
	May	(20,405)	108,089	87,685
	Jun	(160,173)	(140,781)	(300,954)
	Jul	(156,914)	219,298	62,384
	Aug	(163,006)	11,895	(151,111)
	Sep	(62,923)	13,558	(49,365)
	Oct	13,777	(30,654)	(16,877)
	Nov	(46,805)	44,852	(1,953)
	Dec	(41,657)	6,396	(35,261)
	Total	(827,127)	236,974	(590,153)

Note
FTR Auction $ - this is the amount paid to (-) or received from (+) ISO based on the auction clearing price of awarded FTRs
FTR Value $ - this is the amount paid to (-) or received from (+) ISO based on the realized value of the awarded FTRs
Net FTR $ - the sum of the auction dollars and market value of the awarded FTRs
[FTR Value includes partial refund of under-funded target allocations via the ISO-NE Congestion Revenue Fund]

		FTR Quantity	
Source	Month	On-Peak	Off-Peak
Merrimack	Jan - Dec		
	Jan	400	400
	Feb	400	400
	Mar	400	400
	Apr	100	100
	May	100	100
	Jun	400	270
	Jul	350	350
	Aug	400	400
	Sep	300	300
	Oct	125	225
	Nov	400	400
	Dec	275	400
Schiller	Jan - Dec	45	
	Jan	75	75
	Feb	75	75
	Mar	75	75
	Apr	44	50
	May	44	50
	Jun	75	75
	Jul	75	75
	Aug	75	75
	Sep	75	75
	Oct	75	75
	Nov	46	75
	Dec	75	75
Newington	Jan - Dec		
	Jan		
	Feb		
	Mar		
	Apr		
	May		
	Jun		
	Jul	150	
	Aug	200	
	Sep		
	Oct		
	Nov		
	Dec		

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, RCL-2 and RCL-3. Please provide by month for peak, off-peak, and total values and in the form provided in previous dockets: Information on bilateral purchases and costs, spot purchases and costs, and sales of surplus purchases. Actual purchase quantities compared to those in the rate request in both tabular and graphic form. Total supplemental purchases and the percent breakdown by monthly bilateral, short term bilateral and spot purchases. As part of your response, please supply annual figures from 2004 through 2008. Spot sale MWHs and value to ISO-NE from PSNH units and bilateral surplus sales.

Response:
The attached file provides the following information:

Q23-a bilateral and spot market purchase and sale details.
Q23-b compares actual 2008 bilateral and spot market purchase quantities with the forecasted quantities in the Nov 2007 rate request filing. Includes data and two charts.
Q23-c breaks total supplemental purchase quantities into "monthly bilateral", "short-term bilateral" (i.e. less than one month), and "spot market".
Q23-d breaks total surplus sale quantities into surplus generation vs surplus bilateral purchases .

[Q-23a] Summary of 2008 PSNH Bilateral Purchases and ISO-NE Spot Purchases & Sales

Peak

	Total Bilateral Purchases MWh	Total Bilateral Purchases $000	Avg Price $/MWh	Sales of Surplus Purchases MWh	Percent (%) Sold as Surplus	Profit / (Loss) on Sales $000	Total ISO-NE Spot Purchases MWh	Total ISO-NE Spot Purchases $000	Avg Price $/MWh
Jan	128,564	11,450,520	89.06	9,420	7%	24,372	20,123	1,986,826	98.73
Feb	113,926	10,065,298	88.35	4,613	4%	(120,590)	20,244	1,986,365	98.12
Mar	135,394	11,893,738	87.85	18,560	14%	(296,114)	10,967	1,236,048	112.71
Apr	237,456	19,068,812	80.30	26,775	11%	437,936	1,024	258,430	252.45
May	212,692	16,809,516	79.03	35,980	17%	1,001,670	1,669	167,667	100.45
Jun	191,420	17,194,580	89.83	16,441	9%	320,199	10,147	1,406,609	138.62
Jul	179,645	17,354,365	96.60	9,670	5%	136,666	36,271	5,255,185	144.89
Aug	148,319	13,406,532	90.39	21,122	14%	(418,139)	16,490	1,531,985	92.90
Sep	145,429	11,809,466	81.20	4,463	3%	(77,502)	34,898	2,709,154	77.63
Oct	104,414	8,611,115	82.47	915	1%	(23,976)	53,569	3,708,077	69.22
Nov	95,099	7,716,360	81.14	5,817	6%	(150,116)	26,264	1,983,028	75.50
Dec	102,535	8,392,972	81.85	13,277	13%	(396,755)	19,923	1,534,244	77.01
Totals	1,794,893	153,773,275	85.67	167,053	9%	437,652	251,589	23,763,620	94.45

Off-Peak

	Total Bilateral Purchases MWh	Total Bilateral Purchases $000	Avg Price $/MWh	Sales of Surplus Purchases MWh	Percent (%) Sold as Surplus	Profit / (Loss) on Sales $000	Total ISO-NE Spot Purchases MWh	Total ISO-NE Spot Purchases $000	Avg Price $/MWh
Jan	40,802	2,937,057	71.98	5,142	13%	87,097	30,653	2,282,447	74.46
Feb	45,456	3,281,529	72.19	4,660	10%	(80,185)	30,350	2,413,625	79.53
Mar	58,081	4,267,168	73.47	14,274	25%	(71,489)	20,744	1,621,783	78.18
Apr	126,716	8,253,972	65.14	4,385	3%	43,863	23,593	2,041,730	86.54
May	145,654	9,203,587	63.19	41,361	28%	738,340	7,478	704,205	94.17
Jun	76,744	6,257,270	81.53	6,444	8%	(75,201)	41,298	3,985,824	96.51
Jul	84,630	7,522,771	88.89	2,920	3%	(34,891)	67,282	6,574,485	97.72
Aug	65,384	4,917,272	75.21	10,905	17%	(135,612)	18,796	1,384,426	73.65
Sep	46,565	3,188,180	68.47	2,757	6%	(19,858)	64,962	4,313,556	66.40
Oct	44,052	3,004,794	68.21	2,683	6%	(45,695)	34,559	2,120,157	61.35
Nov	50,997	3,562,207	69.85	13,325	26%	(225,849)	23,484	1,475,855	62.85
Dec	45,530	3,137,761	68.92	16,905	37%	(395,967)	16,523	1,344,725	81.38
Totals	830,611	59,533,567	71.67	125,762	15%	(215,447)	379,721	30,262,819	79.70

Total

	Total Bilateral Purchases MWh	Total Bilateral Purchases $000	Avg Price $/MWh	Sales of Surplus Purchases MWh	Percent (%) Sold as Surplus	Profit / (Loss) on Sales $000	Total ISO-NE Spot Purchases MWh	Total ISO-NE Spot Purchases $000	Avg Price $/MWh
Jan	169,366	14,387,576	84.95	14,561	9%	111,468	50,775	4,269,273	84.08
Feb	159,382	13,346,826	83.74	9,273	6%	(200,775)	50,594	4,399,990	86.97
Mar	193,475	16,160,906	83.53	32,834	17%	(367,604)	31,711	2,857,831	90.12
Apr	364,172	27,322,785	75.03	31,161	9%	481,799	24,617	2,300,160	93.44
May	358,346	26,013,103	72.59	77,341	22%	1,740,011	9,147	871,872	95.32
Jun	268,164	23,451,850	87.45	22,885	9%	244,999	51,445	5,392,433	104.82
Jul	264,275	24,877,136	94.13	12,590	5%	101,775	103,553	11,829,670	114.24
Aug	213,703	18,323,804	85.74	32,027	15%	(553,751)	35,286	2,916,412	82.65
Sep	191,994	14,997,646	78.12	7,221	4%	(97,360)	99,860	7,022,711	70.33
Oct	148,466	11,615,909	78.24	3,598	2%	(69,671)	88,128	5,828,234	66.13
Nov	146,097	11,278,567	77.20	19,142	13%	(375,965)	49,748	3,458,883	69.53
Dec	148,066	11,530,734	77.88	30,181	20%	(792,721)	36,446	2,878,969	78.99
Totals	2,625,504	213,306,842	81.24	292,815	11%	222,204	631,310	54,026,439	85.58

[Q-23b]

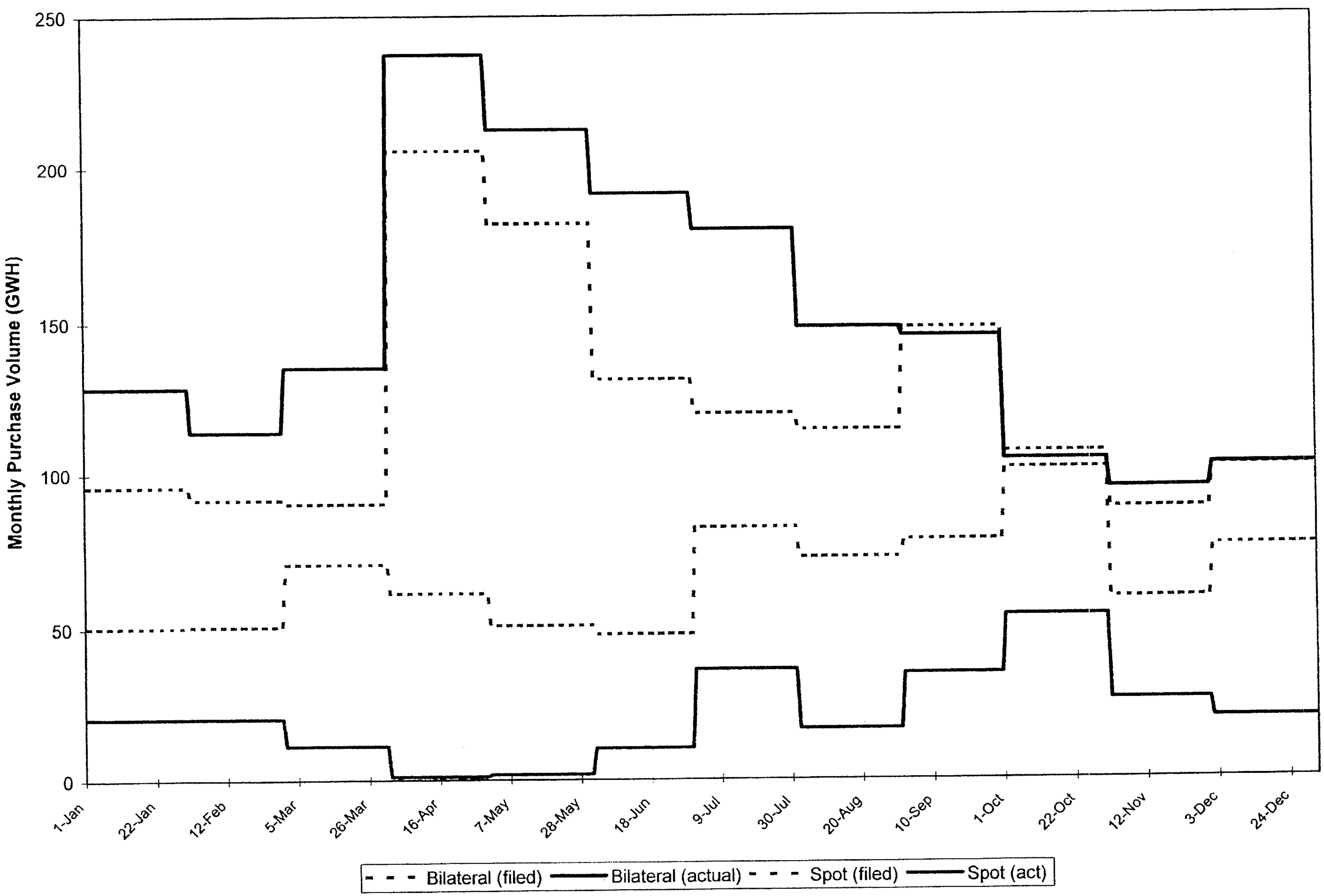
Peak

	Actual 2008 Purchase Quantities		Purchase Quantities Filed with Rate Request	
	Total Bilateral Purchases MWh	Total ISO-NE Spot Purchases MWh	Total Bilateral Purchases MWh	Total ISO-NE Spot Purchases MWh
1	128,564	20,123	95,848	50,295
2	113,926	20,244	91,688	50,596
3	135,394	10,967	90,387	70,750
4	237,456	1,024	205,669	61,346
5	212,692	1,669	181,674	50,879
6	191,420	10,147	131,369	47,936
7	179,645	36,271	119,925	82,287
8	148,319	16,490	114,474	72,527
9	145,429	34,898	148,169	78,132
10	104,414	53,569	106,976	101,384
11	95,099	26,264	88,457	59,111
12	102,535	19,923	102,325	75,851
Totals	1,794,893	251,589	1,476,958	801,096

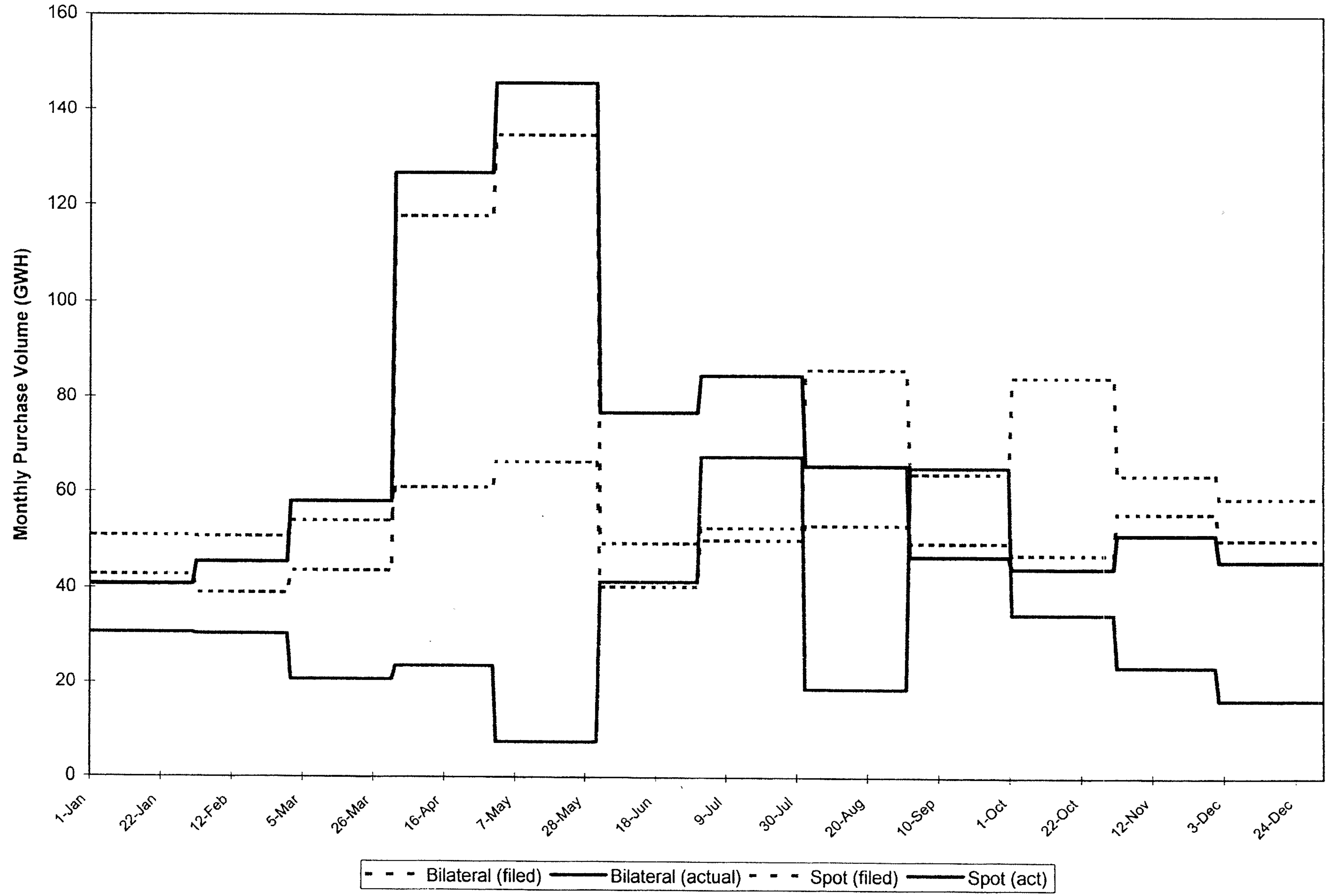
Off-Peak

	Total Bilateral Purchases MWh	Total ISO-NE Spot Purchases MWh	Total Bilateral Purchases MWh	Total ISO-NE Spot Purchases MWh
1	40,802	30,653	42,740	50,843
2	45,456	30,350	39,037	50,641
3	58,081	20,744	43,620	54,011
4	126,716	23,593	117,819	60,948
5	145,654	7,478	134,604	66,207
6	76,744	41,298	49,336	40,301
7	84,630	67,282	49,952	52,452
8	65,384	18,796	53,004	85,812
9	46,565	64,962	49,336	63,633
10	44,052	34,559	46,901	84,202
11	50,997	23,484	55,447	63,389
12	45,530	16,523	49,952	58,528
Totals	830,611	379,721	731,746	730,967

2008 On-Peak Bilateral and Spot Purchase Activity (Actual vs Originally Filed)



2008 Off-Peak Bilateral and Spot Purchase Activity (Actual vs Originally Filed)



Q-23c

Month	On-Peak Power: Total Supplemental Purchases MWh	On-Peak Power: % Monthly Bilateral Purchases	On-Peak Power: % Short-Term Bilateral Purchases	On-Peak Power: % ISO-NE Spot Market Purchases	Off-Peak Power: Total Supplemental Purchases MWh	Off-Peak Power: % Monthly Bilateral Purchases	Off-Peak Power: % Short-Term Bilateral Purchases	Off-Peak Power: % ISO-NE Spot Market Purchases
Jan-04	54,506	92%	0%	8%	13,455	0%	0%	100%
Feb-04	66,872	72%	11%	17%	23,539	0%	0%	100%
Mar-04	141,420	78%	8%	14%	63,115	0%	28%	72%
Apr-04	107,401	98%	0%	2%	49,482	0%	3%	97%
May-04	56,608	0%	42%	58%	23,996	0%	13%	87%
Jun-04	53,239	0%	8%	92%	25,283	0%	19%	81%
Jul-04	89,903	75%	12%	14%	27,426	0%	0%	100%
Aug-04	96,156	73%	12%	15%	39,364	0%	24%	76%
Sep-04	44,180	38%	13%	49%	32,448	0%	79%	21%
Oct-04	139,256	0%	78%	22%	78,562	0%	57%	43%
Nov-04	13,097	0%	18%	82%	40,255	0%	83%	17%
Dec-04	37,819	0%	36%	64%	13,814	0%	12%	88%
Jan-05	77,635	65%	24%	11%	20,082	0%	14%	86%
Feb-05	58,386	44%	32%	25%	25,207	0%	44%	56%
Mar-05	150,227	93%	6%	1%	67,053	85%	0%	15%
Apr-05	100,550	92%	0%	8%	58,987	94%	0%	7%
May-05	191,362	98%	0%	2%	141,334	91%	0%	9%
Jun-05	168,685	89%	2%	9%	105,184	81%	3%	16%
Jul-05	93,220	69%	2%	30%	54,264	68%	6%	26%
Aug-05	109,491	67%	1%	32%	47,339	48%	0%	52%
Sep-05	146,184	83%	2%	16%	71,578	90%	0%	10%
Oct-05	148,895	81%	4%	15%	112,187	78%	1%	21%
Nov-05	111,916	90%	0%	10%	65,306	94%	0%	6%
Dec-05	67,592	87%	0%	13%	78,757	92%	0%	8%
Jan-06	57,045	94%	0%	6%	57,578	81%	0%	19%
Feb-06	130,771	37%	58%	5%	79,510	0%	58%	42%
Mar-06	147,864	100%	0%	0.4%	47,472	81%	0%	19%
Apr-06	176,562	100%	0%	0.3%	126,109	95%	0%	5%
May-06	221,370	95%	1%	4%	129,261	68%	3%	29%
Jun-06	156,009	90%	5%	5%	75,531	91%	0%	9%
Jul-06	121,246	53%	30%	17%	121,614	88%	7%	5%
Aug-06	149,314	49%	28%	23%	92,702	95%	0%	5%
Sep-06	187,516	94%	4%	2%	104,375	57%	8%	35%
Oct-06	158,657	100%	0%	0.2%	70,868	96%	0%	4%
Nov-06	151,615	100%	0%	0.3%	87,183	99%	0%	1%
Dec-06	157,354	92%	4%	5%	114,077	87%	0%	13%
Jan-07	73,910	55%	23%	22.3%	75,638	90%	0%	10%
Feb-07	50,642	73%	11%	16.0%	70,540	87%	5%	9%
Mar-07	115,478	66%	26%	8.7%	58,315	81%	0%	19%
Apr-07	157,269	88%	1%	10.5%	78,215	59%	4%	37%
May-07	194,826	75%	6%	19.1%	112,347	76%	0%	24%
Jun-07	148,246	83%	9%	8.1%	72,858	64%	9%	27%
Jul-07	181,284	77%	14%	8.9%	89,081	79%	0%	21%
Aug-07	193,398	89%	2%	9.4%	92,606	67%	14%	19%
Sep-07	152,442	73%	17%	10.3%	103,988	51%	22%	27%
Oct-07	133,175	73%	10%	16.4%	57,284	75%	0%	25%
Nov-07	107,760	83%	0%	17.3%	54,579	86%	0%	14%
Dec-07	133,305	88%	0%	12.3%	79,321	68%	0%	32%
Jan-08	148,687	63%	24%	13.5%	71,454	56%	1%	43%
Feb-08	134,171	79%	6%	15.1%	75,806	47%	13%	40%
Mar-08	146,361	83%	10%	7.5%	78,824	71%	3%	26%
Apr-08	238,479	100%	0%	0.4%	150,309	84%	0%	16%
May-08	214,361	99%	0%	0.8%	153,132	95%	0%	5%
Jun-08	201,567	81%	14%	5.0%	118,042	50%	15%	35%
Jul-08	215,916	71%	13%	16.8%	151,912	39%	16%	44%
Aug-08	164,809	88%	2%	10.0%	84,180	78%	0%	22%
Sep-08	180,327	81%	0%	19.4%	111,527	42%	0%	58%
Oct-08	157,982	66%	0%	33.9%	78,611	56%	0%	44%
Nov-08	121,363	70%	8%	21.6%	74,481	68%	0%	32%
Dec-08	122,458	80%	3%	16.3%	62,054	73%	0%	27%

2004	900,457	52%	22%	26%	430,738	0%	33%	67%
2005	1,424,144	83%	4%	13%	847,280	79%	3%	18%
2006	1,815,322	85%	10%	5%	1,106,280	79%	6%	15%
2007	1,641,733	78%	9%	13%	944,774	73%	5%	22%

[Q-23d]

2008 On-Peak

	Total ISO-NE Spot Sales MWh	Surplus Sales from Generation MWh	Surplus Sales from Bilateral MWh	Total ISO-NE Spot Sales $000	Avg Sale $/MWh
Jan	9,480	60	9,420	866	91.31
Feb	4,647	34	4,613	287	61.72
Mar	18,819	258	18,560	1,350	71.72
Apr	26,783	7	26,775	2,589	96.66
May	35,981	0	35,980	3,846	106.88
Jun	16,441	0	16,441	1,743	106.04
Jul	9,699	29	9,670	1,064	109.74
Aug	21,161	40	21,122	1,484	70.14
Sep	4,466	3	4,463	285	63.81
Oct	915	0	915	51	56.24
Nov	5,817	0	5,817	313	53.89
Dec	14,985	1,709	13,277	780	52.08
Totals	169,193	2,140	167,053	14,659	86.64

2008 Off-Peak

	Total ISO-NE Spot Sales MWh	Surplus Sales from Generation MWh	Surplus Sales from Bilateral MWh	Total ISO-NE Spot Sales $000	Avg Sale $/MWh
Jan	5,869	727	5,142	485	82.65
Feb	5,362	702	4,660	269	50.16
Mar	17,083	2,809	14,274	1,130	66.13
Apr	4,385	0	4,385	326	74.27
May	42,582	1,221	41,361	3,414	80.16
Jun	6,850	406	6,444	416	60.67
Jul	2,938	17	2,920	210	71.44
Aug	11,837	932	10,905	676	57.15
Sep	2,941	184	2,757	167	56.94
Oct	2,789	106	2,683	130	46.67
Nov	17,455	4,129	13,325	845	48.43
Dec	24,503	7,598	16,905	1,017	41.49
Totals	144,593	18,831	125,762	9,084	62.83

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01
Dated: 06/15/2009
Q-STAFF-024

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, RCL-5. Please explain the approximate 3000 MW increase in ISO-NE capacity resources from January to March and again from September to October.

Response:
See the attached table for a break-out of the various capacity resource categories reported by ISO-NE that contribute to the totals provided in RCL-5. As shown, the increase from January to March is primarily from an increase in qualified imports from neighboring control areas (Hydro-Quebec, New Brunswick and New York) and higher Hydro-Quebec interconnection credits. The increase from September to October is primarily related to the transition from summer seasonal capability ratings to winter seasonal capability ratings.

2008	Total ISO-NE Capacity Resources (MW)	Generation	Load Response	ODR (Other Demand Response)	Imports Contracts	Capacity Credits (NYMPA & HQ)
Jan	35,846	32,222	1,897	328	1,285	115
Feb	35,925	32,246	1,898	381	1,285	116
Mar	38,212	32,320	1,968	380	2,487	1,057
Apr	38,125	32,329	1,941	309	2,487	1,060
May	37,088	31,581	1,979	387	2,285	856
Jun	34,427	29,506	1,557	386	2,285	693
Jul	34,586	29,431	1,548	396	2,388	822
Aug	34,634	29,536	1,411	396	2,388	903
Sep	34,676	29,540	1,483	397	2,246	1,010
Oct	37,941	31,725	2,170	662	2,246	1,138
Nov	37,690	31,817	2,250	657	1,623	1,343
Dec	36,660	31,898	2,341	644	1,642	135
Totals	435,811	374,152	22,442	5,324	24,647	9,247
Mar minus Jan	2,365	98	71	53	1,202	942
Oct minus Sep	3,265	2,185	687	265	0	128

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01
Dated: 06/15/2009
Q-STAFF-025
Page 1 of 2

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Labrecque testimony, RCL-5. Please show and explain how the PSNH percent share for each month was calculated.

Response:
PSNH's share of the ISO-NE capacity obligation shown on Attachment RCL-5 is detailed on the attached table.

	(a)	(b)	(c)	(d)	(e)	(f)
2008	ISO-NE Coincident Peak (MW)	Date & Time of ISO-NE Peak	PSNH Energy Service Customer Coincident Peak	PSNH Share of ISO-NE Obligation (%)	Total ISO-NE Capacity Resources (MW)	PSNH Share of ISO-NE Obligation (MW)
Jan	28,038	Aug 2, 2006 3pm	1,715	6.12%	35,846	2,193
Feb	28,038	Aug 2, 2006 3pm	1,715	6.12%	35,925	2,197
Mar	28,038	Aug 2, 2006 3pm	1,705	6.08%	38,212	2,324
Apr	28,038	Aug 2, 2006 3pm	1,698	6.06%	38,125	2,309
May	28,038	Aug 2, 2006 3pm	1,703	6.07%	37,088	2,252
Jun	25,773	Aug 3, 2007 3pm	1,620	6.29%	34,427	2,164
Jul	25,773	Aug 3, 2007 3pm	1,633	6.34%	34,586	2,192
Aug	25,773	Aug 3, 2007 3pm	1,641	6.37%	34,634	2,205
Sep	25,773	Aug 3, 2007 3pm	1,633	6.34%	34,676	2,197
Oct	25,773	Aug 3, 2007 3pm	1,607	6.23%	37,941	2,366
Nov	25,773	Aug 3, 2007 3pm	1,570	6.09%	37,690	2,295
Dec	25,773	Aug 3, 2007 3pm	1,545	6.00%	36,660	2,198

Notes
- (a) the coincident ISO-NE peak demand from the prior power year (power years run from Jun 1 thru May 31)
- (b) the time of the ISO-NE peak during the prior power year
- (c) this value is the portion of the coincident peak in column (a) attributable to customers served under Rate ES in the given month (e.g. Jan 2008)
- (d) = (c) / (a)
- (e) the total MWs of capacity resources that receive the transition period payment. See Q-STAFF-024.
- (f) = (d) * (e)

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01
Dated: 06/15/2009
Q-STAFF-026
Page 1 of 1

Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Please supply a breakdown in terms of FTEs of the various functions at the NU Regulated Wholesale Power Contracts Department showing which positions PSNH is financially responsible for . If your response is different than in previous years, please show the difference(s) and explain the reason(s) for the change(s).

Response:
The number of FTEs assigned to PSNH support functions is unchanged from 2007. The total FTEs in the department has increased by two (2).

	Total FTEs	PSNH	CL&P & WMECo
Bidding & Scheduling	2.00	1.75	0.25
Resource Planning / Analysis	4.00	2.00	2.00
Energy & Capacity Purchasing	2.00	0.50	1.50
Standard Offer & Default Service Procurement	3.00	0.00	3.00
Contract Administration	3.00	0.00	3.00
Administrative Support	1.00	0.25	0.75
Management	1.00	0.25	0.75
Total	16.00	4.75	11.25

Witness: William H. Smagula
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Stipulated Settlement Agreement in Docket DE 08-066. For the eight recommendations listed on pages 4 through 5: Please describe the actions taken by PSNH to fulfill its commitment to implement recommendations 1 through 7. For recommendation 8, please describe the reviews, etc. performed by PSNH to better understand the protection issues involved.

Response:
The following describes actions taken to date by PSNH to initiate and implement the recommendations in Docket DE 08-066.

1. PSNH should review the foreign matter exclusion procedure and modify it to include a check for foreign materials at the end of each shift as well as the current end of job inspection. He further recommends that when a unit is opened for maintenance, the senior crew person be required to sign off that all foreign materials have been removed prior to closing the unit.

PSNH Generation station management has reviewed its foreign matter exclusion (FME) practices at all of its fossil stations. Based on investigation and review of specific incidents at Merrimack Station a revised FME procedure has been written. This procedure has gone through a number of revisions and reviews and is undergoing final approvals. This FME procedure will be provided to the other stations as the key reference for developing an FME policy as appropriate for local applicability and enhancements. The equipment tagging procedure has been reviewed with all personnel which requires the the equipment is ready for operation, including checking for any foreign material, prior to signing off the tags by the responsible maintenance person.

2. PSNH should evaluate the use of a roving practices and procedure person during an outage to ensure that practices, procedures, and safety requirements are being followed per PSNH instructions. This practice should be implemented at all plants and is applicable for all outages.

PSNH Generation has reviewed the use of a roving practices and procedures person for use during an outage. With the number and variety of tasks associated with practices, procedures and safety requirements, it was determined that these responsibilities could and should be distributed among key outage personnel including the maintenance manager, maintenance supervisors, working foreman, and contractor liaisons. After a lengthy review, we have concluded that delegating these functions to a specific person or persons inappropriately shifts this responsibility from the subject matter experts who also are fully accountable for these functions. Our preferred approach has been, and continues to be, to re-emphasize these duties throughout these groups. The entire work force also reviews safety and associated practices and procedures prior to the start of any job using the STAR program. The STAR program is a recently instituted program geared to cause the workers performing each maintenance job to fully evaluate all aspects of the work before initiating the work.

3. PSNH should evaluate original equipment that does not have an inspection schedule and determine if and when such a schedule should be established. He recommended that PSNH should also evaluate equipment that does currently have an established inspection schedule and determine if that schedule should change with the aging of components. These recommendations apply to all major units.

PSNH Generation leadership and station managers conducted a work session to review this topic. The long and broad experience of this group provided the best knowledge of the units' equipment and inspections. A review was made by system as well as by the equipment in the plants. From that review, some enhancements were emphasized to further improve plant reliability. A few examples are: broader boiler NDE programs/vendors, and flow assisted erosion of critical piping systems.

4. PSNH should not rely exclusively on aerial patrols for inspections of lines in rights-of-way and that all lines in a right-of-way be inspected from the ground.

As part of the REP request included in PSNH's recently filed rate case, a proposal has been made to fund patrolling of distribution lines in ROW on a yearly cycle utilizing a combination of aerial and ground methods.

5. PSNH should consider a) moving check valves that show a propensity for sticking so that those valves may be unstuck without disturbing other systems and b) exercise care in the placement of check valves. Mr. Cannata further recommended that PSNH conduct an informal survey to identify other areas that exhibit the potential for similar problems.

PSNH Generation leadership and station managers conducted a work session to review this topic. The long and broad experience of this group provided the best knowledge of the units' check valve locations and potential operational risks for them sticking. A review of check valves and their placement in critical systems identified key systems, as well as related work practices, which should be reviewed. (i.e. the turbine extraction non-return valves and lube oil system check valves). The survey found only 2 check valves hung up and one check valve was replaced as a result of the review.

6. An outage occurred at Schiller Station when the wrong switch was activated by an operator. In the main control panel the switches are located in one configuration while the remote control panel located at the combustion turbine the switches are in an opposite or different configuration. Mr. Cannata recommended that PSNH identify potential problems with switching locations at its generating stations where there are two systems with different configurations, thereby preventing similar operator errors in the future.

PSNH Generation leadership and station managers conducted a work session to review this topic. The long and broad experience of this group provided the best knowledge of the units' equipment and operational configuration. A review was done on appropriate controls which have multiple or redundant locations. The group determined that no systemic problems exist. However, a further review of labeling will be made to insure clear and observable markings exist at remote (outside the control room) redundant controls. Examples of such systems are: combustion turbines, hi-yards and motor-control-centers.

7. PSNH should check the lightning protection in the area of the Canaan hydro unit to assure that its lightning protection practices will not result in lightning damage to the unit.

PSNH has reviewed the lightning protection in the area of the Canaan hydro and confirmed that the lightning protection in the area is in accordance with PSNH's distribution engineering guidelines. The area, specifically the lightning protection equipment, was also visually inspected. All the equipment was found in tact and installed properly.

8. PSNH should set distribution system protective settings in the future such that local generation is not impacted. In addition, Mr. Cannata recommended that PSNH review existing distribution system settings and do whatever is possible to minimize impacts to local generation.

This effort has been initiated with Distribution Protection and Control Engineering (D-P&CE) reviewng generator voltage and overcurrent settings when it is perceived that 34.5 kV feeder protection system changes or additions may impact the operation of local PSNH generation.

PSNH completed a study in 2009 which checked local generator voltage relaying coordination versus distribution 34.5 kV feeder coordination. The results of this study showed that except for Canaan Hydro, all other sites met coordination margins defined as 0.45 seconds or greater when the undervoltage relays (type ICRs) are set to factory published settings. Canaan hydro's worst case coordination margin was 0.35 seconds which is slightly less than our desired target margin but which is still deamed as acceptable for this unit at this location. PSNH D-P&CE is issuing setting letters to the PSNH Hydro Generation group to allow them to confirm and/or set all type ICR relays to factory settings.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01

Dated: 06/15/2009
Q-STAFF-028
Page 1 of 1

Witness: William H. Smagula
Request from: New Hampshire Public Utilities Commission Staff

Question:

Reference Smagula testimony, page 4. Please provide the specifics for each bullet under each topic.

Response:

Mr. Smagula's testimony reiterated recommendations by Liberty Consulting as listed below and confirmed that PSNH Generation continues to consider, as a whole, these items in the management of the facilities.

Optimizing availability with:

- on-line maintenance
- redundant equipment to shorten forced outage time
- appropriate replacement parts and spare parts inventory
- assessment of inspection scopes and schedules for the equipment at the facilities,
- locating or relocating equipment with high risk of outages for better operation and maintenance
- review of switching locations at the generating stations where there are two systems with different configurations.
-

Specifics of the above include: continued use of vendors like Team, Inc who attempt on-line leak-stop to avoid or delay a forced outage; purchased spare air heater baskets to change out rather than clean baskets and shorten outage durations; continued refurbishment by Generation maintenance of replaced equipment; expanded boiler tube NDE's consistent with aging areas; completed targeted surveys of equipment, i.e. check valves; completed survey to identify any areas where two systems exist with different configurations that result in a concern of mis-operation. Generation has recently completed an electrical relay testing and calibration survey, while continuing its boiler, high-pressure piping and feedwater heater non-destructive examination initiatives.

During planned and forced outages maintaining, as examples:

- effective efforts to ensure that practices, procedures and safety requirements are being followed
- contractor value through effective contractor control
- a rigorous foreign matter exclusion procedure.

PSNH Generation has not only reviewed its own practices, procedures, and safety requirements, but also is collaborating with outside vendors to share process and expand resources. PSNH Generation also continues to work with both its purchasing department and/or its vendors to obtain the most knowledgable companies and their most knowledgable employees, specifically on critical work items in the plants. Two of these items are specifically discussed in the response to STAFF-01, Q-STAFF-027.

Witness: William H. Smagula
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Smagula testimony, page 17. With regard to the planned maintenance outage for Merrimack 2 that commenced on 4/1: Please provide the economic analysis that justified the replacement of the HP/IP turbine. Include all assumptions as part of your response. Please provide your calculations of the net economic impact to energy costs of the results of the HP/IP turbine replacement from the beginning of the initial outage on 4/1 through the 2009 planned maintenance outage. In your response, please identify and explain each economic impact. If PSNH has any insurance related to the HP/IP replacement, please describe the coverage and how it applies. Please describe the guarantees PSNH had from Siemens regarding the performance of the new HP/IP turbine compared to the old turbine. Please provide the details and root causes of any investigation performed by PSNH or its suppliers regarding the intrusion of foreign material into the HP/IP turbine. Please include any reports or relevant communications from each. Please describe the foreign material exclusion process at Merrimack station and how it was applied to the installation of the new HP/IP turbine.

Response:
Attached, please find the economic analysis that culminated from a 2+ year inquiry into the replacement of the HP/IP turbine. It was prepared recognizing an approximately 18-month lead time required for design and manufacturing of the turbine. This discussion and analysis summarized early estimates of a variety of items that would provide value to customers.

- HP/IP Turbine Replacement Cost -early estimate of $9M
- Increased energy efficiency - early estimate of 6 - 10 megawatts
- Avoided maintenance costs during the 2008 outage - $1.8M
- Avoided maintenance costs in 2013 totaling $2-4 million, estimate due to a 10- year inspection cycle rather than a 5-year inspection cycle
- No additional outage time when completed during the 2008 major 8-week outage since the replacement would take no longer than the alternative repair approach

This analysis estimated a pay back period of about 18 months assuming:

- an 8 megawatt increase associated with the improved efficiency
- $81.75/mwhr market price of generation
- 75% capacity factor of the unit
- a capacity value of $6.37/kw-mo

<u>Economic Impact</u>. PSNH interprets this question to request aditional information regarding not only the initial replacement of the HP/IP turbine, but also the subsequent inspection and eventual repair due to the damage to the new HP/IP turbine during the 2008 annual outage start-up. With that, there are 3 outages associated with either the planned HP/IP turbine replacement or subsequent inspection and repair of the HP/IP turbine due to the foreign material that passed through the turbine upon start-up from the April-May annual outage.

First, the Merrimack 2 Annual Outage in April-May 2008 was completed 51 hours ahead of its scheduled ISO window. There were a number of long projects completed during the outage, including the HP/IP turbine replacement, and none of them exceeded the ISO window and thus there was no incremental outage cost (energy costs) to customers associated with the HP/IP replacement.

Second, the inspection outage of Merrimack 2, including the damage to the new HP/IP turbine, and other boiler and balance of plant equipment, required an unplanned outage from June 20 through July 14, 2008. This forced outage has an estimated cost of $13.2 million. The necessity of this outage was to identify equipment problems and insure safe operations of the turbine.

Third, the damage to the new HP/IP turbine is planned to be repaired during a 2009 outage beginning August 1. It is expected that this repair outage will last 18 weeks to bring the turbine to an as new condition. A 2009 annual outage planned for 4 weeks was originally scheduled to occur in the spring of 2009. This outage work will be shifted to occur during the HP/IP repair outage. The net impact of this repair work is an additional 14 weeks of outage. The estimated cost of this additional 14 weeks of outage is $5.2.million.

Insurance. Merrimack Station does have insurance coverage which includes boiler and machinery repairs. There is a $1 million deductible associated with this coverage. Merrimack Station also has replacement power insurance coverage. In this instance, the replacement power coverage has two components: the additional forced outage time associated with the equipment damage, as well as the lost incremental generation associated with the new, more efficient HP/IP turbine. There is a 60-day exclusion period prior to the beginning of the replacement power coverage. There are also daily maximums equal to $417,000/day for the months of December, January, February, June, July, and August $316,000/day for the months of March, April, May, September, October and November. Finally, there is a $31 million dollar total cap. Once the "deductible" period is met, the insurance claim will include both the outage time, described above, and the lost incremental generation. The actual value of the incremental generation will be determined by performance tests that will be completed once the new HP/IP turbine is fully repaired and brought back to an "as-new" condition at the end of the 2009 outage.

Contractual Guarantees. The turbine had a minimum output guarantee equivalent to the original unit output. Secondly, the replaced turbine had a ten-year warranty effective from the time of completion of certain performance tests which would be critical in the determination of additional output. Because the output determinative performance testing has been delayed until December of 2009 (which was done in fairness to a vendor who has a pay-per-performance clause in the contract), the parties agreed that at that time, following the testing on fully repaired turbine, a nine-year warranty will go into effect (the turbine will have been functioning approximately a year and a half by that time).

Investigation. The initial effort was the external review while the unit remained on line. Once the unit was off line and based upon the initial findings, PSNH and Siemens expanded the internal turbine inspection and brought in expert organizations to analyze and identify the foreign material and the root cause of its presence.

Beginning on June 24, 2008, PSNH personnel, Siemens and key vendors inspected steam and meter system equipment and valves for evidence of foreign material contamination, and others provided assistance in chemistry and metallurgy analysis. PSNH was supported by the following firms:

- Siemens Power Corporation
- Thielsch Engineering
- Team Industrial Services
- GE Inspection Technologies
- Baker Testing
- Sheppard T. Powell Associates
- Babcock & Wilcox
- NH Material Laboratory
- Alstom Power

The scope of necessary inspections broadened beyond the originally planned HP-IP turbine inspection. PSNH determined that it was essential to know what equipment and systems contained the foreign material found in the turbine. The material found was commercially available "shot blast" which is small beads of steel used for cleaning metallic surfaces. These inspections would indicate any other damage that occurred, determine requirements for removal of all shot blast material found, and assist in the effort to remove all material and help determine the entry point of this material and the root source. These actions would also assist with ensuring there would be no subsequent damage of a similar nature. The scope expanded into the LP-1 and LP-2 turbines, condensate and feed water systems, boiler headers and tubes, and turbine piping, and other related systems.

Metallurgical analysis of the foreign material was conducted by the three independent laboratories. Those analyses identified an abrasive material that was a chrome-bearing steel alloy, spherical in shape, ranging in diameter from 0.01 - 0.03 inches. The type of material was like that used for a sandblasting process. An investigation as to the source of the material and mode of introduction into the steam system was undertaken.

Preliminary conclusions included the following:

(1) Significant quantities of foreign material entered and passed through the turbine during the initial hours of operation of the unit startup.
(2) The hard dense nature of the foreign material led to the observed solid particle erosion damage to the blade path, seals, casing and rotor.
(3) The observed conditions would be consistent with the operating conditions reported following the return to service on May 22 (high turbine pressure, reduced flow passing capability, decreased turbine efficiency levels, and reduced power output).

On July 11, 2008, PSNH and representatives from Siemens, Babcock & Wilcox and Sheppard T. Powell Associates conducted an "Apollo" root cause review to determine a root cause of the contamination. The Apollo technique focused on the cause and effect of the relationships based upon existing or obtainable evidence and data with each cause identified as being the result of both a cause and an action. A number of possible causes were ruled out during the session while other causes were identified as requiring additional information or further evaluation. Although the analysis to date showed the contamination to be shot blast material, no definitive conclusions were reached by the Apollo analysis as to the source of the material.

Summary Observations

PSNH personnel conducted a root cause analysis to determine the source of the shot blast material found inside the turbine. PSNH personnel reviewed the following information:

-- Merrimack Station inspection results
-- possible sources for the origination of the shot blast material
-- quality assurance measures that were taken at manufacturing facilities during fabrication of the turbine piping and boiler tubes
-- quality assurance measures that were taken at Merrimack Station during installation
-- report of samples that were sent out for analysis

As summarized in the PSNH Fossil Station Outage Report issued after the completion of the outage and included in the May 1 filing, inspections showed material was contained to the following systems and equipment:

-- HP/IP Turbine
-- HP/IP Turbine extractions and associated feedwater heating components
-- Main Boiler Feed Pump
-- LP Turbine
-- LP Turbine extractions and associated condensate heating components, Condenser Hotwell, Condensate Pumps, DA Pumps, and Condensate Polisher.

Conclusion - Indeterminate Cause / Single Event (May 22-23, 2008)
PSNH has been unable to reach definitive conclusions for the entry point of the contamination or the source of the material. PSNH concluded it appeared to be from a single event that occurred on May 22-23 during the initial start-up. These conclusions were based upon the following information:

- The unit did not experience a degradation of output over time but rather never reached its design load. There was no further degradation of output over the subsequent 28-day operation.
- Some valves downstream from the turbine experienced malfunction during the start-up indicating that the material traveled through the turbine extraction lines and caused problems with the condensate and feedwater heater level control valves.
- After ramp-up at approximately 130 MW output, scaling data was available and observed. It was noted at this point that the actual performance data did not match the supplied Siemens design curves for the new turbine.
- Unit 2 maintained a constant output and no further degradation after returning to service from this outage although it was less than the designed output.
- PSNH has never purchased the contaminant material for use at Merrimack Station and no other on-site contractors used it on-site.

Foreign Material Exclusion (FME) Policy. The Merrimack Station FME Practice is for all station work and has as a primary focus the systems and equipment associated with the steam-water cycle used to generate electricity. The level of detail as well as the expansiveness of the program is based on the work and the direction set by the Maintenance Manager. Very simply, the FME program requires unattended openings to be covered to prevent material from entering the water/steam side of the process, and new material is inspected, blown out or boroscoped to prevent material from entering the cycle. Individuals are designated as inspectors who have FME as a primary focus, supplementing operators, maintenance personnel, station management and others who all contribute to constant monitoring. Also, contractors who do work are well versed on this program and incorporate necessary practices and inspections as part of their work. Every contractor has a PSNH liaison or sponsor who also has FME oversight responsibility. Specific to the turbine work, Siemens has a long standing FME program that addresses the equipment and turbine and peripherals work scope that is honored by all who are in the turbine vicinity during outages.

The current Merrimack Station FME Practice is attached.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01

Dated: 06/15/2009
Q-STAFF-031

Witness: William H. Smagula
Request from: New Hampshire Public Utilities Commission Staff

Question:
Please supply 2008 budgeted and actual capital and O&M expenditures for Merrimack, Schiller, and Newington stations separately and the hydro units as a group.

Response:
This first table provides the 2008 budgeted and actual capital for Merrimack, Schiller and Newington Stations separately and the hydro units as a group.

GENERATION SUMMARY
YTD December 2008

	CAPITAL	YTD ACTUALS
MERRIMACK STATION*	BUDGET	31,126.4
	ACTUAL	34,376.9
	VARIANCE	3,250.5
SCHILLER STATION	BUDGET	10,417.4
	ACTUAL	7,649.4
	VARIANCE	-2,768.0
NEWINGTON STATION	BUDGET	1,112.9
	ACTUAL	2,512.4
	VARIANCE	1,399.6
HYDRO	BUDGET	5,765.7
	ACTUAL	3,746.2
	VARIANCE	-2,019.6

PSNH FLEET	BUDGET	48,422.5
	ACTUAL	48,284.9
	VARIANCE	-137.5

* reflects MK1and MK2 major planned outages, does not include CAP

This second table provides the 2008 budgeted and actual O&M expenditures for Merrimack, Schiller and Newington Stations separately and the hydro units as a group.

December 2008 O&M

	YEAR-TO-DATE			
Station	**Budget (Latest Approved**	**Actual**	**Over/ (Under) Budget**	**Percent Over/ (Under) Budget**
Merrimack	42,993	41,577	(1,416)	-3.3%
Schiller	19,472	17,473	(1,999)	-10.3%
Newington	8,576	7,237	(1,338)	-15.6%
Hydro	6,700	6,920	220	3.3%

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-01

Dated: 06/15/2009
Q-STAFF-032
Page 1 of 1

Witness: William H. Smagula
Request from: New Hampshire Public Utilities Commission Staff

Question:
Please supply summaries of the scheduled maintenance outages that took place at Merrimack, Schiller, and Newington stations in 2008.

Response:
Please see the attached table.

Unit	Outage Dates	Planned Maintenance Outage
Merrimack #1	9/9 – 11/03 (8 weeks)	This planned outage included major turbine work completed every 5 to 6 years, as well as normal cyclical boiler, turbine auxiliaries and balance of plant mechanical, electrical and instrumental repair and maintenance. The unit was taken off line September 9 and returned to service October 29, 120 hours ahead of the ISO schedule. Major work items included HP and LP turbine work, 18 SSH inlet pendant replacement, partial boiler screen tube replacement, switchgear replacement and replacement of layer 3 of the SCR catalyst. A number of other balance of plant items were inspected, maintained, repaired or replaced, as necessary.
Merrimack #2	4/1 – 5/22 (8 weeks)	This planned outage included major turbine work completed every 5 years, as well as normal cyclical boiler, turbine auxiliaries and balance of plant mechanical, electrical and instrumental repair and maintenance. The unit was taken off line April 1 and returned to service May 22, 263 hours ahead of the ISO schedule. Capitalized projects included the HP/IP turbine replacement, generator rotor replacement, air heater tube replacement, boiler floor replacement, selective catalytic reducer (SCR) catalyst replacement, and secondary superheater (SSH) inlet bank replacement. An extensive list of work has been included in Docket 08-145, Data Request Set TS-01, Q-Staff-002.
Newington #1	3/1 – 3/13 (2 weeks)	This planned outage included normal boiler, turbine auxiliaries and balance of plant mechanical, electrical and instrumentation repair and maintenance. Newington Station was taken off line on March 1, 2008 @ 00:00 and returned to service March 13, 2008 @ 01:36 for a total duration of 12.07 days. The ISO-NE scheduled outage window was 3 weeks (23 days). The outage critical path was the inspection of the 6 large (2,000 + hp) motors. The motor inspections, including disassembly and electrical testing, are completed to help ensure their ongoing availability and reliability. In addition to the routine annual testing, inspections, and repairs of plant systems and components, the Turbine/Generator and Main Boiler Feed Pump/Turbine Control System hardware was upgraded during the overhaul. The control system upgrade include replacement of all power supplies, processors, and the Control Room Operator's interface computers.
Schiller #4	3/25 – 4/10 (2 weeks)	This planned outage included normal boiler, turbine auxiliaries and balance of plant mechanical, electrical and instrumentation repair and maintenance. The unit was scheduled to be removed from service at 22:00 on Tuesday, March 25th and to be returned to service at 07:00 on, Friday April 11th (17 day schedule). The unit came off at 21:46 on Tuesday March 25th, and was returned to service at 11:36 April 10th, approximately 19 hours ahead of the original ISO completion date. The critical path work scope was to the ID fan. Boiler work included a thorough inspection of the entire boiler after being staged. Miscellaneous pad welding and shielding of several areas were performed through out the boiler. Refractory was renewed and replaced as was necessary. New Opacity monitors were installed during this shutdown. The main steam line flow orifices were inspected as well as the feedwater flow orifices. Both sets were found to be in good condition. A number of other balance of plant items were inspected, maintained, repaired or replaced, as necessary.

Docket No. DE 09-091
Data Request STAFF-01
Dated: 06/15/2009
Q-STAFF-032
Attachment

Schiller #5	10/17 – 10/27 (1-2 weeks)	This planned outage included boiler, turbine auxiliaries and balance of plant mechanical, electrical and instrumentation repair and maintenance. The unit was scheduled to be removed from service at 22:00 on Friday, October 17th and to be returned to service at 07:00 on, Monday October 27th (10 day schedule). The unit came off at 19:02 on Friday October 17th, and was returned to service at 10:40 October 27th approximately 4 hours behind the original ISO completion date. Turbine over-speed test was successfully performed when the unit was taken off-line. Critical path for the outage was the repair of brick lining material of the six boiler cyclones. Boiler work included a thorough inspection of the entire boiler after being staged; this was performed by United Dynamics Corporation as well as the Authorized inspector. Routine refurbishing of major control valves was performed. Maintenance of wood feed equipment including the feeder screw drives, silo pawls, and wood chutes. A number of other balance of plant items were inspected, maintained, repaired or replaced, as necessary.
Schiller #6	4/11 – 4/26 (2 weeks)	This planned outage included normal boiler, turbine auxiliaries and balance of plant mechanical, electrical and instrumentation repair and maintenance. Unit 6's outage was re-scheduled to be removed from service at 22:00 on Friday April 11th and returned to service at 07:00 on, Monday April 28th (17 day ISO schedule). The unit came off at 21:45 on Friday April 11th, and was returned to service at 09:43 April 26th, approximately 45 hours ahead of the ISO 17 day planned scheduled. Turbine over-speed test was successfully performed when the unit was taken off-line. Critical path for the outage was the rebuilding of the boiler bottom ash system, including the water-cooled door jackets and associated brick hopper lining. Boiler work included a thorough inspection of the entire boiler after being staged. The authorized inspector was in and performed the annual operating inspection for permitting. A service engineer from Foster-Wheeler was requested in to inspect the boiler as well, minor items were noted and corrected as recommended. A number of other balance of plant items were inspected, maintained, repaired or replaced, as necessary.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request STAFF-02

Dated: 08/14/2009
Q-STAFF-005

Witness: William H. Smagula
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference response to OCA-01, Q-OCA-021. Please provide details regarding the reference insurance claim and its payment status. The information provided should address such issues as: when it was submitted, description of the coverage, whether PSNH has received any information from the insurance company related to its claim, etc.

Response:
The following provides a summary of the insurance coverage, requested reimbursement amounts, and payment status.

Boiler and Machinery: — deductible $1M
(i.e. property damage)

Replacement power (specific to MK2):
(RPC)
— 60 day waiting period
-- Daily Cap $417K/daily max Dec-Feb, Jun-Aug
-- Daily Cap $316K/daily max Mar-May, Sept-Nov
-- Policy Cap $31M

COVERAGE

Replacement Power	Amount	Status
2008- June thru October	$3 million	submitted and paid as part of $6M advanced payment 1
2008- November, December	$1.5 million	submitted Q1 09
2009- Q1 January-March	$2.1 million	submitted Q2 09
2009- Q2 April - Jun	$1.1 million	submitted Q3 09

Property Damage		
2008- May - July	$3 million	submitted and paid as part of $6M advanced payment 1
2008- December	$2 million	submitted Q1 09 (milestone payment to Siemens)
2009- June	$1.3 million	submitted Q3 09 (milestone payment to Siemens)
2009- August	$6.7 million	submitted Q3 09 (milestone payment to Siemens)

PSNH has provided documentation for all property damage items submitted to date in 2009 and is awaiting reimbursement.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-01

Dated: 07/28/2009
Q-OCA-009
Page 1 of 1

Witness: **Richard C. Labrecque**
Request from: **Office of Consumer Advocate**

Question:
Attachment RCL-1 shows the PSNH resource portfolio winter and summer entitlements. The totals don't match these on Att. RCL-5, PSNH capacity resources, so please reconcile the 2 Attachments.

Response:
The table below provides a break-out of the PSNH Capacity Resources column from Attachment RCL-5. The primary difference between RCL-1 and RCL-5 is that RCL-1 lists the seasonal ratings (aka seasonal claimed capabilities or SCC) whereas RCL-5 is based on the monthly unforced capacity ratings (UCAP) assigned to each asset by ISO-NE. Each asset's UCAP rating is essentially the SCC reduced by an outage factor that accounts for the asset's historical average performance. Many of these outage factors change each month; thus the monthly deviation from RCL-1. The other differences are that the Hydro-Quebec Interconnection Credits are only applicable for March through November, and that RCL-5 includes the capacity contribution from three PPAs (Bethlehem, Tamworth, and Lempster) whereas RCL-1 does not.

Month	PSNH Generation & IPPs	Vermont Yankee	Hydro-Quebec Interconnection Credits	PSNH Capacity Resources (MW)
Jan	1,233	20	0	1,253
Feb	1,236	20	0	1,256
Mar	1,236	20	129	1,385
Apr	1,238	20	129	1,387
May	1,235	20	129	1,383
Jun	1,190	19	129	1,338
Jul	1,170	19	129	1,318
Aug	1,166	19	129	1,314
Sep	1,164	19	129	1,312
Oct	1,205	20	129	1,353
Nov	1,231	19	129	1,379
Dec	1,256	20	0	1,276
Totals	14,559	234	1,160	15,953

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-01

Dated: 07/28/2009
Q-OCA-010
Page 1 of 1

Witness: **William H. Smagula**
Request from: **Office of Consumer Advocate**

Question:
The Attachment included with the response to Staff 01-029 is the Merrimack Station Capital Project Justification. Included in that is a section labeled justification. Please update the payback period calculation based on actual costs and energy/capacity values for 2008.

Response:
PSNH has not prepared such an analysis. Moreover, such an analysis would subject the project to a hindsight review, especiallly if one used 2008 data to estimate future costs. In light of this and in view of the OCA's ability to update the requested project justification on its own, PSNH is not uniquely situated to perform such analysis. As a result, PSNH has no information responsive to this question.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-01

Dated: 07/28/2009
Q-OCA-011
Page 1 of 1

Witness: **Richard C. Labrecque,Robert A. Baumann**
Request from: **Office of Consumer Advocate**

Question:
Please provide a detailed breakdown of the costs included in this filing for PSNH's supplemental energy sources department. Are there other costs in the filing related to acquiring or selling power? Are there other costs not included in the filing? Please explain.

Response:
PSNH's Supplemental Energy Sources Department O&M charges are recovered through distribution rates; thus, this filing does not include any of those costs. The Northeast Utilities Wholesale Power Contracts (NU WPC) department charges O&M associated with purchasing power to energy service. These costs are included in RAB-4 page 13, line 2 "F/H Operation & Maintenance Costs". During 2008, NU WPC charged $766,260 to energy service. This includes direct charges, employee costs and company overheads.

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Data Request OCA-01

Dated: 07/28/2009
Q-OCA-012
Page 1 of 1

Witness: **Richard C. Labrecque**
Request from: **Office of Consumer Advocate**

Question:
Following up on Staff 01-010, please explain what services will now be handled by PSNH's Supplemental Energy Sources Department as opposed to the Wholesale Power Contracts Department of NU Service Co. Why has PSNH made this change?

Response:
There has been no change in the services that will be supplied by the two noted departments. A single employee (Richard Labrecque) has accepted a recently vacated position (in Supplemental Energy) and, thus, departed his old position (in Wholesale Power Contracts).

Public Service Company of New Hampshire	**Data Request OCA-01**
Docket No. DE 09-091	**Dated: 07/28/2009**
	Q-OCA-013
	Page 1 of 1

Witness:	**Richard C. Labrecque**
Request from:	**Office of Consumer Advocate**

Question:
On p. 4 lines 23-28 Mr. Lebrecque describes when PSNH's supply resources exceeded its needs, and how the company sold those resources in the spot market for $23.7 million. Did those sales result in additional expense for ES customers, or did they provide a net benefit to customers?

Response:
These surplus sales resulted in a net benefit to customers of approximately $245,000.

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Docket No. DE 09-091

Data Request OCA-01

Dated: 07/28/2009
Q-OCA-014
Page 1 of 1

Witness: **Richard C. Labrecque**
Request from: **Office of Consumer Advocate**

Question:
On page 6 line 9 of Mr. Lebrecque's testimony, he points out that in 2008 PSNH was allocated 6.17% of ISO-NE's capacity obligation. Please explain the actions PSNH took to reduce that percentage or its ES Customer Coincident Peak.

Response:
PSNH's Voluntary Interruption Program (Rate VIP or "PeakSmart") was successfully implemented at the time of the ISO-NE system coincident peak during both the summer of 2006 and 2007. The curtailed MW and the associated customer capacity expense savings are detailed below.

Time of ISO-NE Peak	ISO-NE Peak	PSNH Peak	Rate VIP Curtailment (MW)	Rate VIP as % of ISO-NE Peak	Impact on Settlements
2006 Aug 2nd hour end 15:00	28,038	1,767.24	6.23	0.022%	Jun '07 - May '08
2007 Aug 3rd hour end 15:00	25,773	1,670.65	6.73	0.026%	Jun '08 - May '09

	Total ISO-NE Capacity Resources (MW)	Rate VIP Savings (%)	Rate VIP Savings (MW)	Transition Period Payment Rate ($/MW-mo)	Capacity Savings ($)
Jan-08	35,846	0.022%	7.97	3,050	$24,301
Feb-08	35,925	0.022%	7.99	3,050	$24,355
Mar-08	38,212	0.022%	8.49	3,050	$25,905
Apr-08	38,125	0.022%	8.47	3,050	$25,846
May-08	37,088	0.022%	8.24	3,050	$25,143
Jun-08	34,427	0.026%	8.99	3,750	$33,717
Jul-08	34,586	0.026%	9.03	3,750	$33,872
Aug-08	34,634	0.026%	9.05	3,750	$33,919
Sep-08	34,676	0.026%	9.06	3,750	$33,960
Oct-08	37,941	0.026%	9.91	3,750	$37,158
Nov-08	37,690	0.026%	9.84	3,750	$36,912
Dec-08	36,660	0.026%	9.57	3,750	$35,904
			106.62		$370,992

Public Service Company of New Hampshire	**Data Request OCA-01**
Docket No. DE 09-091	**Dated: 07/28/2009**
	Q-OCA-015
	Page 1 of 1

Witness:	**Richard C. Labrecque**
Request from:	**Office of Consumer Advocate**

Question:
On page 8 line 18 of Mr. Lebrecque's testimony he explains that the 2008 impact of PSNH's participation in the ISO-NE FTR (Financial Transmission Rights) auction process was an increase in ES expense of $590,153. What was the comparable net gain or losses for all prior years in which PSNH was active in this process?

Response:
See the table below.

	Net Gain / (Loss)
2003	73,574
2004	76,311
2005	119,154
2006	(167,414)
2007	160,000

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-01

Dated: 07/28/2009
Q-OCA-016
Page 1 of 1

Witness: **Richard C. Labrecque**
Request from: **Office of Consumer Advocate**

Question:
Besides the $590,153 noted in the prior question, what additional Administrative costs were charged to ES in 2008 related to the FTR (Financial Transmission Rights) process? Please provide the work papers, and reconcile with the responses to Staff 01-026.

Response:
PSNH's participation in the FTR market is administered via the Northeast Utilities Wholesale Power Contracts department (NU WPC). The O&M charges associated with NU WPC are provided in the response to Q-OCA-011. NU WPC staff do not track hours worked specifically on the adminstration of FTRs versus other duties related to the provision of energy service. However, a rough estimate would be 5 staff-hours per month, which equates to less than 1% of total time, given the 4.75 Full Time Equivalent staffers from Q-STAFF-026.

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Docket No. DE 09-091

Data Request OCA-01

Dated: 07/28/2009
Q-OCA-017
Page 1 of 1

Witness: **William H. Smagula**
Request from: **Office of Consumer Advocate**

Question:
Please explain how PSNH's generating sector was impacted by the December 2008 Ice Storm.

Response:
The generating facilities did not experience any damage associated with the December 2008 ice storm.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-01

Dated: 07/28/2009
Q-OCA-018
Page 1 of 1

Witness: **William H. Smagula**
Request from: **Office of Consumer Advocate**

Question:
If any generation sector employees were "loaned" to the Distribution sector to assist in the December Ice Storm restoration, please explain in detail.

Response:
A limited number of generation employees were loaned to distribution. Generation employees were loaned only after approval from generation management was obtained, which confirmed that no generation activities would be impacted.

Public Service Company of New Hampshire
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Data Request OCA-01

Dated: 07/28/2009
Q-OCA-019
Page 1 of 1

Witness: **Robert A. Baumann**
Request from: **Office of Consumer Advocate**

Question:
Are 100% of all ISO-NE credits received by PSNH automatically credited to ES customers? If not, please explain. Similarly, are 100% of all ISO-NE credits received by NU and allocated to PSNH automatically credited to ES customers? If not, please explain.

Response:
Generation related credits received from ISO-NE on PSNH's bill or allocated to PSNH from the NU bill are all booked when received and credited to PSNH's ES customers.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-01

Dated: 07/28/2009
Q-OCA-020
Page 1 of 1

Witness: **Richard C. Labrecque**
Request from: **Office of Consumer Advocate**

Question:
Referring to Staff 01-012, Actual Customer Migration started to greatly exceed estimates in November, 2008 and continued in December. What steps did PSNH take at that time to minimize costs to the remaining ES customers?

Response:
As customer migration increases, the energy required to serve default energy service customers decreases. PSNH and NU Wholesale Power Contracts staff continuously monitor the load and supply resource balance and make portfolio adjustments to serve the remaining DES customers with the optimal mix of available resources. This may require curtailing production from the least economic generation resource or reselling surplus power into the market. The magnitude of the migration increase during November and December 2008 did not require any notable, significant portfolio adjustments.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-01

Dated: 07/28/2009
Q-OCA-021
Page 1 of 1

Witness: William H. Smagula
Request from: Office of Consumer Advocate

Question:
Referring to Staff 01-031, page 1 of 2, why were the 2008 capital expenditures for Newington Station more than twice those budgeted?

Response:
When Newington Station was returning to service after its scheduled overhaul, the main generator's exciter was subjected to a thermal excursion which resulted in the exciter needing extensive repairs or replacement. PSNH obtained a rebuilt exciter rotor which avoided delays associated with the replacement or repair of the failed exciter, which could have taken up to 6 months. The rebuilt exciter rotor replacement cost $1.5 million resulting in Newington exceeding its capital budget by $1.4 million. PSNH has submitted an insurance claim for the associated property damage. There was no replacement power cost associated with this outage.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-01

Dated: 07/28/2009
Q-OCA-022
Page 1 of 1

Witness: **Robert A. Baumann**
Request from: **Office of Consumer Advocate**

Question:
Attachment RAB-2 lists the outages and corresponding replacement power costs. Please confirm that these costs occur during station outages. Please provide the same table that notes which outages are related to the Merrimack Station Outages for both the turbine replacement and the turbine malfunction.

Response:
Attachment RAB-2 includes outages and related replacement power costs for all unscheduled outages in excess of two days at either Newington Station or at the two units at Merrimack Station; and in excess of four days at the three units at Schiller Station and Wyman. Attachment RAB-2 does not include annual scheduled maintenance outages. Annual outages are scheduled with ISO to insure the system has adequate generation capabilities and to minimize disruptions.

There are three outages associated with the MK turbine replacement, two of which occurred in 2008 and one that will take place in 2009 as noted below:

(1) 2008 planned HP/IP turbine replacement - outage start on 04/01/08 at 1346 through 05/22/08 0804 totaling 50.8 days
(2) 2008 inspection outage related to HP/IP performance and subsequent finding of foreign material - June 20 - July 14, 2008 and
(3) 2009 scheduled repair of the HP/IP turbine due to the foreign material issues found in the June-July 2008 outage.

The first outage was part of an annual scheduled maintenance outage, and accordingly, not included on RAB-2. As stated in response to data request Staff 01, Q-Staff-029 in this docket, "Merrimack 2 Annual Outage in April-May 2008 was completed 51 hours ahead of its scheduled ISO window. There were a number of long projects completed during the outage, including the HP/IP turbine replacement, and none of them exceeded the ISO window and thus there was no incremental outage cost (energy costs) to customers associated with the HP/IP replacement."

The second outage of Merrimack 2 related to inspection of the new HP/IP turbine performance, and other boiler and plant equipment which required an unplanned outage from June 20, 2008 through July 14, 2008. This forced outage has an estimated replacement power cost of $13.2 million as shown and listed on Attachment RAB-2.

The third outage will occur in 2009 beginning August 1. It is expected that this repair outage will last 18 weeks. A 2009 annual scheduled outage planned to take 4 weeks was originally scheduled to occur in the spring of 2009. This outage work was shifted to occur during the HP/IP repair outage. Therefore, the net impact of this repair work is an additional 14 weeks of outage. The estimated cost of this additional 14 weeks of outage is $5.2 million.

In addition, please see the response to OCA-01, Q-OCA-023 which further discusses the replacement costs and potential insurance proceeds.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-01

Dated: 07/28/2009
Q-OCA-023
Page 1 of 1

Witness: **William H. Smagula**
Request from: **Office of Consumer Advocate**

Question:
Referring to Staff 01-029, page 2 of 4, the Merrimack Station outage that lasted from June 20 to July 14, 2008 has an estimated cost of $13.2 million included in energy service for 2008. a. Please explain if that includes replacement power costs. b. Is this amount net of $6 million in insurance proceeds booked in December 2008? c. What is the net amount related to this outage of June 20-July 14, 2008 included in this reconciliation docket? d. Are additional proceeds expected that will be netted against the total 2008 costs?

Response:
The response to Staff 01-029 understood the question to ask for the impact to energy costs, that is "Please provide your calculations of the net economic impact to energy costs of the results of the HP/IP turbine replacement from the beginning of the initial outage on 4/1 through the 2009 planned maintenance outage." The response outlined the energy costs associated with each of the 3 outages requested. Specifically the "inspection outage of Merrimack 2, including the damage to the new HP/IP turbine, and other boiler and balance of plant equipment, required an unplanned outage from June 20 through July 14, 2008. This forced outage has an estimated cost of $13.2 million." Therefore, in response to a) above, the $13.2 million estimated cost is the replacement power cost associated with the inspection outage from June 20 through July 14. In response to b), this same response to Staff-029, page 2 of 4, goes on to explain that " There is a 60-day exclusion period prior to the beginning of the replacement power coverage." This inspection outage occurred during the replacement power exclusion period. c) The expense costs associated with this outage are included in the reconciliation docket. These inspection outage costs were submitted to the insurance company as part of the claim and were reimbursed as part of the $6 million insurance payment. d) Replacement power costs associated with November and December 2008, approximately $1.5 million, have been submitted as part of the insurance claim. Payment for this cost has not yet been received.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-01

Dated: 07/28/2009
Q-OCA-024
Page 1 of 1

Witness: **Richard C. Labrecque**
Request from: **Office of Consumer Advocate**

Question:
As a follow up to confidential responses Staff 01-009, what was the net cost to ES customers of PSNH's continued ownership and operation of Newington Station? Please provide the work papers.

Response:
The Newington Station 2008 revenue requirements are provided in Staff 01-009. There are no additional work papers.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-01

Dated: 07/28/2009
Q-OCA-025
Page 1 of 1

Witness: **Richard C. Labrecque**
Request from: **Office of Consumer Advocate**

Question:
As a follow-up to confidential responses Staff 01-030 and 009, please show the annual net cost /benefits to ES customers of PSNH's continued ownership and operation of Newington Station. Please provide the work papers.

Response:
PSNH understands the question to be seeking a forecast of the 2009-2013 Newington Station revenue requirements, including fuel and O&M, in relation to the potential ISO-NE market revenues associated with the facility. PSNH does not maintain such a forecast.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-02

Dated: 08/14/2009
Q-OCA-009
Page 1 of 1

Witness: **Richard C. Labrecque**
Request from: **Office of Consumer Advocate**

Question:
Referring to the response to OCA 1-015, please explain why the FTR loss in 2008 was more than three times greater than any prior year since 2003. Has PSNH made any changes to its FTR approach in light of the 2008 loss? Please explain.

Response:
The level of transmission congestion throughout New Hampshire and all of ISO-NE declined significantly in 2008 relative to prior years. Therefore, many of the financial congestion hedges (aka Financial Transmission Rights) that PSNH procured via auction had a cost that exceeded the realized congestion price differentials.

PSNH's general approach to FTRs has not changed, but our bidding behavior in the auctions has been adjusted to reflect the recent trend of lower transmission congestion; i.e. our bid prices are generally lower in 2009 than in 2008.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-02

Dated: 08/14/2009
Q-OCA-010
Page 1 of 1

Witness: **William H. Smagula**
Request from: **Office of Consumer Advocate**

Question:
Referring to the response to OCA 1-018, what was the period that generation employees where "loaned" to distribution during the Ice Storm? During this was any of their compensation charged to generation? If so, how much? Please provide the supporting work papers.

Response:
The majority of the generation employees loaned to distribution assisted during the period beginning the week of December 14 and ending the week of December 27. In a few instances, close-out work was completed during the next couple of weeks. None of the loaned employees' compensation for any of the storm support work was charged to generation.

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Data Request OCA-02

Dated: 08/14/2009
Q-OCA-011
Page 1 of 1

Witness: William H. Smagula,Robert A. Baumann
Request from: Office of Consumer Advocate

Question:
Referring to the response to OCA 1-021, what is the status of the insurance claim for Newington Station, and what is the amount of the claim?

Response:
The insurance claim has been submitted for an amount of $773,443.95. The insurance holder has indicated that the loss is a covered event and the claim is currently proceeding through the adjustment process.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-02

Dated: 08/14/2009
Q-OCA-012
Page 1 of 1

Witness: **William H. Smagula,Robert A. Baumann**
Request from: **Office of Consumer Advocate**

Question:
As a follow up to the responses to OCA 1-022 and 1-023 as well as Staff 1-003 and Staff 1-029, please provide an update on the status of insurance proceeds for the Merrimack Station outage in June and July 2008 due to foreign matter. Has the full amount of insurance proceeds been received? If so, what is the total? If not, when does the Company expect to receive all insurance proceeds for the outage?

Response:
The full amount of insurance proceeds associated with the June/July 2008 outage due to foreign material has been received. As stated in OCA 1-23, the expense costs, included as part of the property damage coverage, were reimbursed as part of the $6 million insurance payment. As stated previously, the $6 million payment includes approximately $3 million dollars for O&M expenses associated with the property damage through July and approximately $3 million associated with the replacement power costs for June through October. This insurance payment was included as a credit to costs in the filing made in this docket.

See Staff-02, Q-Staff-005 for additional information regarding the insurance coverage and claim.

Witness: William H. Smagula
Request from: Office of Consumer Advocate

Question:
Referring to the responses to Staff 1-027 and Staff 1-029, please provide the prior "Foreign Matter Exclusion Policy" or practices for its fossil stations. Please also provide a comparison of the old policy and the new one, noting the changes. What is the status of the policy provided and dated 7/3/09? When did it go into effect?

Response:
PSNH's generating facilities employ similar foreign material exclusion (FME) practices. Using Merrimack Station as an example, the station utilizes what would be considered industry standard and commonly used practices. For example, when a valve is removed from a piping system, any openings are protected with some form of covering or plug for the period of time the valve is removed. When a section of pipe or tube is removed, the ends are typically wrapped and taped. New components, such as boiler tubing, that are to be installed are inspected for foreign material and blown out with compressed air prior to installation. Visual or borescope inspections are made on critical equipment prior to closure. The PSNH employee in charge of each job is responsible for FME requirements. Also, specific to the steam turbine generators, Siemens (formerly Westinghouse) follows their own FME procedures. To a large degree, these procedures are consistent with those of Merrimack Station regarding the protection of openings and inspection of equipment.

The process of foreign material exclusion from any Merrimack Station system or equipment has essentially remained the same, focusing on the protection of openings so that material cannot enter during on-going maintenance work and then inspecting the openings prior to closure. Changes that have been implemented are summarized as follows:

<u>Additional checks and balances</u>
In order to ensure the reliability of the FME practice, specific personnel are designated to have additional oversight roles and they perform walk-downs of all FME-related jobs during major outages. A list of these jobs is maintained and the controls in place for each item are checked for integrity.
<u>Designated FME Roles</u>
Responsibilities for FME roles are assigned by management. This effort may include just the person performing the work for a routine, non-shutdown job to one or more people performing the duties during an outage. Designation of responsibilities provides greater accountability.
<u>Documentation</u>
Records of inspections and control checks will be maintained. This provides confirmation of efforts to ensure FME and assists the facility to monitor these activities to ensure that no areas have been overlooked.

In summary, the major change that was made from past and present FME practices is that the new practice is clearly formalized and documented, while additional or secondary oversight is utilized as deemed appropriate by the maintenance manager.

The Foreign Material Practice, Revision 6, dated 7/3/09 is the current, approved version for Merrimack Station. This Foreign Material Practice, Revision 6, went into effect prior to 8/1/09 for use at the beginning of the Unit 2 planned Annual Outage.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-02

Dated: 08/14/2009
Q-OCA-014
Page 1 of 1

Witness: William H. Smagula
Request from: Office of Consumer Advocate

Question:
Referring to the response to Staff 1-031, please explain what "CAP" means in the footnote to the table. Why is "CAP" not included in the table only for Merrimack Station? What are the amounts of "CAP" for the station?

Response:
"CAP" is the acronym for the Clean Air Project, i.e. the scrubber project, and thus is only applicable to Merrimack Station. CAP for the station was $27.5 million.

Public Service Company of New Hampshire
Docket No. DE 09-091

Data Request OCA-02

Dated: 08/14/2009
Q-OCA-015

Witness: William H. Smagula
Request from: Office of Consumer Advocate

Question:
Referring to the response to Staff 1-032, please explain in detail how the company was able to return Merrimack Unit 2 to service 263 hours ahead of schedule on May 22, 2009.

Response:
In 2007, PSNH requested from ISO-NE a scheduled outage window of just over 8 weeks for Merrimack Station which began April 1 at 1400 and ended June 2 at 0700. This outage duration was PSNH's best estimate for the time needed to complete outage work in the following year. During the outage planning process, which is completed in the months prior to the start of the outage, the Station produced an outage schedule of about 53 days. This schedule included the replacement of the generator rotor, rather than a repair of the generator rotor, which shortened the generator rotor work scope duration by an estimated 2 weeks. The final outage duration was 50.8 days, 51 hours ahead of the planned outage schedule and 263 hours ahead of the ISO-NE outage window.

Public Service Company of New Hampshire
Docket No. DE 09-091

Technical Session TECH-01

Dated: 09/10/2009
Q-TS-001
Page 1 of 1

Witness: **William H. Smagula**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Please update Staff Set 02, Q-STAFF-005 to reflect Newington insurance information not Merrimack II. What was the remaining value of the Newington rotor. Please indicate whether this value is net book, salvage or some other value. When would PSNH have replaced the rotor at Newington Station?

Response:
Newington Station installed a re-qualified exciter rotor assembly from the Seimens rotor seed program (discussed below). Total costs associated with this project submitted to date are \$1,773,443.95. The insurance coverage associated with this event, includes a Boiler and Machinery (property damage) component which has a \$1 million deductible. There is no replacement power cost associated with this event and therefore no replacement power insurance claim. The insurance holder has indicated that the loss is a covered event and the claim is currently proceeding through the adjustment process. Initial data was submitted 2008 Q3. Additional data, follow up and requested information was submitted 2008 Q4. In 2009 Q2, insurance broker confirmed the claim was in the review process. To complete the claim settlement, PSNH has recently been requested to provide additional documentation of costs and supporting information and discussion. This additional information has been submitted to the insurance broker.

The Newington Station exciter assembly, including the exciter rotor, was the original equipment from 1974, and fully depreciated which gave it a net book value (plant in service net of accumulated depreciation) of \$0.

There was not a specific replacement date for the Newington exciter rotor. To minimize the risk of failure, prior to the replacement of the exciter, Newington Station performs major disassembly inspections during generator inspections. The field inspection procedure was developed by Westinghouse in the mid 1980's. To better manage exciter rotor availability and reliability due to the frequency of failures, Seimens has also developed a rotor seed program to avoid long lead time deliveries and lengthy forced outage when a failure occurs. As exciters age there are a number of risks that can arise including cracks occurring in the shaft, damage occurring to the diode wheel forgings, rims and hubs, cracks occurring in the phase lead shield, etc. . These issues result in failures and major damage which require the exciter assembly to be repaired, refurbished or replaced. The newly installed exciter rotor assembly at Newington Station has eliminated the risk associated with the continued operation of the original exciter.

This replacement was completed with no replacement power costs and was done at a cost of \$1million dollars, the insurance deductible, as compared to a replacement in the future which would have been no less than \$1.7 million and possibly significantly more depending on the corrective actions necessary. With this rotor exchange, PSNH management was successful in negotiating a cap to potential repair costs associated with Newington's turned-in rotor. These repair costs could have added hundreds of thousands of dollars to this completed project or a future seed rotor exchange project.

Public Service Company of New Hampshire
Docket No. DE 09-091

Technical Session TECH-01

Dated: 09/10/2009
Q-TS-002
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Witness: Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:

Please update Staff Set 01, Q-Staff-026 to reflect the percentage of time charged to PSNH by each individual in the Wholesale Power Contracts Department to PSNH Generation.

Response:

At year end 2008 there were 16 employees in Wholesale Power Contracts. The table below shows the percent of their productive time that each employee charged to PSNH Generation. Each employee is classified by an indicative job title.

Position	Productive Time Charged to PSNH Generation
Supervisor / Manager / Director	2%
Supervisor / Manager / Director	0%
Supervisor / Manager / Director	34%
Supervisor / Manager / Director	18%
Supervisor / Manager / Director	100%
Engineer / Analyst	0%
Engineer / Analyst	0%
Engineer / Analyst	0%
Engineer / Analyst	0%
Engineer / Analyst	0%
Engineer / Analyst	73%
Engineer / Analyst	89%
Engineer / Analyst	24%
Engineer / Analyst	94%
Engineer / Analyst	50%
Administrative Support	1%
Total	32%

Public Service Company of New Hampshire
Docket No. DE 09-091

Technical Session TECH-01

Dated: 09/10/2009
Q-TS-004
Page 1 of 3

Witness: **William H. Smagula,Richard C. Labrecque**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
If Newington Station was not part of PSNH's portfolio for 2010, what measures would PSNH prepare differently to serve the load and power requirements for its Energy Service customers in that year?

Response:

Please refer to data request DE 08-113, TS-01, Q-TECH-002 (copy attached) for a general discussion of Newington's value to customers.

To replace Newington in the 2010 supply portfolio, PSNH would evaluate a number of different options, none of which is a perfect replacement.

1. Procure firm replacement power at a fixed market price (e.g. 400MWs for the entire year). This power would be available as a hedge against market price increases and unplanned outages at PSNH's baseload stations. This option would involve the risk that power market prices are less than the purchase price, and that the surplus power is resold to the market at a loss, recoverable from customers.

2. Same as option #1, except different volumes, e.g. 200MWs in the volatile months of Jan, Feb, Jul, & Aug. The risks of reselling surplus are similar to option #1 but this option also invoves the risk that an insufficient volume of replacement power was procured and that PSNH's customers are exposed to market prices.

3. Procure Call Options that provide PSNH the right, but not the obligation, to procure power at a fixed price on a daily or monthly basis. These Call Options could also be indexed to the daily spot market for residual fuel oil or natural gas (whichever is less expensive), to more closely mimic Newington's dual fuel capability. Call Options, especially those indexed to daily commodity market prices, are not standard market products and would require direct negotiations with a limited set of potential suppliers to agree on price and terms.

In all options, the recovery of all replacement costs and all market risks involved would be in addition to the continued recovery of Newington's 2010 non-fuel revenues requirements via the ES rate.

Witness: William H. Smagula, Richard C. Labrecque
Request from: New Hampshire Public Utilities Commission Staff

Question:
Technical session question 2 from OCA --- Please provide reasoning as to why continued operation of Newington is beneficial to customers, both in qualitative and quantitative manner.

Response:
Please refer to the following data requests that discuss the benefits to customers of continued operation of Newington:

DE 07-108	NSTF-01	Q-STAFF-020	(Apr 18, 2008)
DE 08-066	NSTF-01	Q-STAFF-006	(Jul 29, 2008)
DE 08-066	NSTF-01	Q-STAFF-008	(Jul 29, 2008)
DE 08-066	NSTF-01	Q-STAFF-008-F01	(Jul 29, 2008)
DE 08-113	NSTF-01	Q-STAFF-10	(Oct 7, 2008)

During 2007, 2008, and perhaps again in 2009, Newington's primary customer benefit is the ISO-NE capacity market. Newington provides approximately 4,800 MW-months of capacity to the ISO-NE market. Currently, capacity is valued at $3,750 per MW-month. This escalates to $4,100 starting in June 2009 and to $4,250 starting June 2010. The future price of capacity is unknown. That price will be determined by periodic auctions administered by ISO-NE. At the $4,250 per MW-month value, Newington's capacity is worth $20.4 million per year. This $20.4 million is a direct reduction to Energy Service costs, and thus benefits Energy Service customers.

In addition to capacity value, Newington can generate 400 MW of energy per hour to serve a significant portion of Energy Service load. Customer benefit associated with this energy is both "financial" and "physical". Newington is used in power supply planning as a "financial hedge" that precludes the need to execute firm, fixed-price supplemental energy contracts. If the price of oil in inventory or under future contract is economic versus the forward bilateral energy market, planners can utilize forecasted production from Newington to avoid more expensive supplemental contracts. During actual week-to-week and day-to-day operation of PSNH's system, Newington is used as a "physical" hedge. When ISO-NE spot market prices exceed Newington's fuel cost, the unit can be dispatched to create customer benefits. Using Newington is superior in many ways to using bilateral contracts, primarily due to the ability to follow hourly load and to be used only when needed (versus a monthly bilateral contract which is for a fixed amount of power for the entire month).

Newington also provides customer value during periods when economic energy production is not forecasted (i.e. when the forward market price for energy exceeds Newington's variable production costs). As a reserve asset, Newington can be used in planning as a form of power supply insurance to respond to infrequent periods of increased demand (i.e. during a forced outage at one of PSNH's baseload unit or when extreme weather leads to higher customer usage). When these occasions arise, Newington is available as a physical asset capable of producing energy at a known price (i.e. the fuel cost times the conversion efficiency of the unit). This insulates customers from the uncertain and volatile ISO-NE market, in which merchant generators are not required to offer their energy to ISO-NE at cost-based rates. Without Newington on reserve, PSNH's planners would need to evaluate costly forms of power supply insurance to address these infrequent, but potentially expensive, periods.

Additionally, Newington is able to burn either residual fuel oil of natural gas. Thus, the unit can provide economic energy value to customers in a variety of possible commodity market price scenarios. Not only does this create direct benefits for customers, but it provides energy security value to all of New England. Specifically, Newington's ability to burn an inventory of on-site oil is critical during winter periods when extreme demand for natural gas can strain the ability of gas-fired generators to serve ISO-NE loads. This can occur during periods of extremely cold weather and during gas supply emergencies that can disable multiple large-scale generating facilities. During these times, not only are ISO-NE spot market prices extremely volatile, but the overall reliability of the ISO-NE system may be compromised. When there is a gas supply shortage, dispatchable, oil-fired power plants are essential for ISO-NE reliability.

Public Service Company of New Hampshire
Docket No. DE 09-091

Technical Session TECH-01

Dated: 09/10/2009
Q-TS-005
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Witness: **William H. Smagula**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Please complete

a) the attached table - "Merrimack Station Unit 2 2008 Costs Related to Foreign Material Damage to Turbine,
b) indicate the total coverage of each policy, the respective deductibles, and the remaining coverage available after taking account of the amounts reported in each column on the table.

Response:
a) The attached table has been populated with the information requested.

b) The total coverage policy associated with replacement power is $31 million per event with a 60-day exclusion (deductible) period. The requested reimbursement for replacement power during 2008 was $4.5 million of which $3 million was received and booked in December 2008. Additional requests for replacement power cost reimbursement are being made in 2009.

The boiler machinery (property damage) has a deductible of $1 million with no policy cap. During 2008, covered expenses of $3 million were requested, and $3 million were received and booked in December 2008. Additional requests for maintenance expense reimbursement are being made in 2009.

In summary, the following identifies the insurance coverage deductibles and caps.

Boiler and Machinery: --- deductible $1M
(i.e. property damage)

Replacement power (specific to MK2):
(RPC)
-- 60 day waiting period
-- Daily Cap $417K/daily max Dec-Feb, Jun-Aug
-- Daily Cap $316K/daily max Mar-May, Sept-Nov
-- Policy Cap $31M

Merrimack Station Unit 2 2008 Costs related to Foreign Material Damage to Turbine						
	Total (Gross) Costs	Avoided Costs due to Plant out of Service	Net Cost and Date Expense Booked to Energy Service	Insurance Amounts Received to Date	Date(s) Insurance Proceeds Booked to Energy Service	Status & Amounts of Additional Insurance Claim Amounts not yet received
Replacement Power Costs (RPCs)						
Jun 1 – Jul 31 2008	$19.1M	$5.9M	$13.2M(1) Date:Jun, Jul	NA(2)	--	NA(2)
Aug 1 – Oct 31 2008	$3M(3)	$0M(5)	$3M(3) Date:Aug,Sep,Oct	$3M	Dec 2008	$0
Nov 1 –Dec 31 2008	$1.5M(5)	$0M(5)	$1.5M Date:Nov,Dec	$0M	--	$1.5M Submitted 2009-Q1
Property Damage Expense						
Jun 1 – Jul 31 2008	$3M	$--	$3M(4) Date:Jun- Sep	$3M(6)	Dec 2008	$0
Aug 1 – Oct 31 2008	$0M	$--	$-- Date:	$--	--	NA
Nov 1 –Dec 31 2008	$0M	$--	$-- Date:	$--	--	NA

(1) $13.2M RPC associated with turbine inspection outage from June 20 – July 14 (all within the 60 day exclusion period)
(2) No insurance due to 60 day exclusion period
(3) Includes last 10 days of July
(4) Costs incurred during June, July; billing/payments over subsequent months
(5) RPC generation losses during August – December are associated with incremental generation and therefore have no avoided costs.
(6) The $1M deductible will be deducted from the final payment expected in 2010.